Analysing the integration of different types of energy and reserve providers in a competitive electricity supply market

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**ANALYSING THE INTEGRATION OF DIFFERENT
TYPES OF ENERGY AND RESERVE PROVIDERS IN
A COMPETITIVE ELECTRICITY SUPPLY MARKET**

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Summary

Deregulation of the electric power industry has unbundled a single electric power entity into separate business entities in the past two decades in many developed countries. The introduction of competition in the electricity market allows generation plants of different types, inclusive of renewable energy, and demand side management (DSM) to offer their energy and reserve. The main objectives of this new electric power industry are to reduce the cost that the consumers have to pay for electricity and to alleviate damage on the environment from electric power production. The choice of fundamental energy resources for generation has become an important factor in energy planning, since their availabilities and cost of extraction have a direct effect on the selection of generation types for electricity generation to achieve the objectives of the new electric power industry. The operating characteristic of these generation types is another factor that will influence the overall operating efficiency of the electric power system.

In this thesis, a 10-minute operating reserve requirement (ORR) scheduling which integrates the probabilistic approach into the Unit Commitment (UC) function via a deterministic reserve criterion is presented to determine the reserve. The UC problem is modelled by Mixed Integer Programming (MIP) which is coded using General Algebraic Modelling System (GAMS) and is solved by the solver CPLEX 10.2.

The impact of demand side participation for reserve offering in the electricity market is analysed. The issues, on how the interruptible loads (ILs) may influence and affect the electricity market, and power system economic and reliability, are addressed. A penalty cost is imposed on IL service providers who are responsible for the maintenance of under-frequency relays and circuit breakers connected to ILs. This thesis also presents how the incorporation of ILs will affect the system EENS.

Improving in technology and manufacturing process of turbine construction has caused an investment switch from conventional large thermal units to small gas turbine units. These gas turbines, such as open cycle gas turbines (OCGTs), a type of rapid-start units, have a short start up time and a high ramp rate. They are called upon to serve during plant outages and system contingencies. However, these OCGTs have poor starting reliability, which is undesirable in energy scheduling and reserve allocation. In this thesis, a joint probability distribution approach is proposed to incorporate the starting reliability into the operating reliability of the rapid-start units. A methodology for modelling the rapid-start units and for considering the start up time needed for non-spinning reserve contribution is presented. The expected energy not served (EENS) terms computed from different energy and reserve providers are then pictorially presented. The EENS diagram provides a better understanding on the un-served energy caused by different providers. A penalty calculation scheme which penalises rapid-start units which fail to start up for reserve contribution is proposed. The importance of modelling the rapid-start units with starting reliability in the UC problem is illustrated.

Hydro units, a type of rapid-start generator, are examined. In this study, constraints such as cascaded plants, reservoir contents and spillage, etc, which are environmentally dependent are modelled in the UC problem. In addition, conventional thermal units are incorporated in the study to examine the combined effect of the hydro and thermal generating system on reliability and economics, as well as the reserve procured at a specific reliability level.

A methodology is then proposed to integrate the forecast errors of the uncertain wind energy production due to sporadic wind flow, and the fluctuation of system demand in the formulation of EENS. The system reserve is then determined via the UC problem to optimise the system total energy, reserve and EENS costs. The availability of the wind turbine is modelled in the thesis. Variations of wind energy penetration for different load levels are performed in order to delve into the reserve

requirement study for the wind turbine system. Finally, generation mix is considered to investigate the electric power system reliability and economics with different source providers.

The proposed methodologies and results obtained in this thesis can be used by generation companies (Gencos) for effective resources planning through understanding on how to maximise their profits. At the same time, the developed software can serve as a useful tool for independent system operator (ISOs) to deploy energy/reserve providers more efficiently in the electric power system. The operating characteristic of each energy/reserve provider will influence the energy scheduling and reserve allocation shares in the electricity market.

List of Acronyms

AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
ARMA	Auto-Regressive Moving Average
AWEA	American Wind Energy Association
CAISO	California Independent System Operator
CBA	Cost/Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CO ₂	Carbon Dioxide
COPT	Capacity Outage Probability Table
CPLEX	C Programming Language and Simplex Method
CRE	Energy Regulation Commission
DSAs	Demand Side Agents
DSB	Demand Side Bidding
DSM	Demand Side Management
Discos	Distribution Companies
EDF	Electricité de France
EENS	Expected Energy Not Served
EMA	Energy Market Authority
EMC	Energy Market Company
GAMS	General Arithmetic Modelling System
Gencos	Generation Companies
HA	High Availability
I/O	Input/Output
IESO	Independent Electricity System Operator
IEA	International Energy Agency

ILs	Interruptible Loads
IPP	Independent Power Producer
ISO	Independent System Operator
LA	Low Availability
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LT	Lead Time
MIP/MILP	Mixed Integer Linear Programming
MTTF	Mean Time To Failure
MW	Megawatt
MWh	Megawatt Hour
NEM	National Electricity Market
NEM ¹	New Electricity Market (Singapore)
NEMMCO	National Electricity Market Management Company
NEMS	National Electricity Market of Singapore
NERC	North American Electric Reliability Council
NO _x	Nitrogen Oxide
NR	Non-Spinning Reserve
NYISO	New York Independent System Operator
OCGTs	Open Cycle Gas Turbines
OR	Operating Reserve
ORR	Operating Reserve Requirement
PJM	Pennsylvania – New Jersey – Maryland
PSO	Power System Operator
PV	Photovoltaic
PX	Power Exchange
RES	Renewable Energy Source
RTE	Gestionnaire du Réseautage Transport de l' Electricité
SCADA	Supervisory Control And Data Acquisition
SF ₆	Sulphur Hexafluoride

SO ₂	Sulphur Dioxide
SR	Spinning Reserve
STOR	Short Term Operating Reserve
Transcos	Transmission Companies
UC	Unit Commitment
UCR	Unit Commitment Risk
UFR	Under-Frequency Relay
UK	United Kingdom
US	United States
VIU	Vertically Integrated Utilities
VOLL	Value of Lost Load
WS	Wind Speed
WTG	Wind Turbine Generator

List of Symbols

α	Accuracy of forecast error [%]
ε	A diminutive value which can be preset by the system operator. This study has ε set to 2% of $EENS_{\max}$.
λ	Failure rate
Γ	time constant for thermal unit i [h].
τ	A lead time variable [h]
v	Time delay of upper reservoir [h]
x	A variable number for wind turbine
π_l	Reliability factor of IL l
$\sigma_{l,t}$	Standard deviation of load at hour t [MW]
$\sigma_{total,t}$	Standard deviation of net forecast errors [MW]
$\sigma_{w,t}$	Standard deviation of forecast error at hour t for wind energy production [MW]
$\omega_{a/b}$	Status of wind speed (1 or 0)
$\theta_{i,t}$	Binary status for unit i outage at hour t
θ_t^0	Binary status on the loss of load owing to large net forecast error without unit outage at hour t
$\theta_{i,t}^f$	Binary status on the loss of load with unit i outage at hour t
$\Phi(\cdot)$	A normalised distribution function
$\sum Outage\ MW$	summation of MW outages of the units and non-dispatchable WTGs that have been scheduled for operation and the summation only considers up to third order outages [MW].
$\sum R$	Summation of all available reserve [MW]

a, b	Indices of the unit combination elements
$A_{l,t}$	Availability of unit l at hour t
$A_{l,t}^{IL}$	Availability of unit l computed with unit reliability at hour t
$AOMW_t$	Actual outage megawatt at hour t [MW]
$B_1^{ils} / B_2^{ils} / B_3^{ils}$	Reserve price offered by DSA 1, 2 and 3 [\$/MWh]
C_i^E	Cost of output power from committed unit i [\$/h]
C_i^{MG}	Cost of power selling from micro-grid i to main grid [\$/h]
C_i^{rs}	Cost of reserve from offline rapid-start unit i [\$/h]
C_i^{SR}	Cost of spinning reserve from committed unit i [\$/h]
C_i^{ils}	Cost of reserve from DSA i [\$/h]
$CFnos$	Number of possible combinations of WTG outages
com	A set that comprises outage orders of different energy and reserve providers at hour t , i.e. $com = \{(k, i), (k, i, j), (j, k, i)\}$
$comIL$	A set of all ILs that failed to disconnect from the grid when their services are required
cr_i^c	Cold-start cost for unit i [\$/MBtu]
cr_i^{fixed}	Fixed cost for unit i [\$/h]
cr_i^{rs}	Non-Spinning Reserve (NR) bidding price from offline rapid-start unit i [\$/MWh]
cr_i^{SR}	Reserve bidding price from online unit i [\$/MWh]
cr_i^{SU}	Start up cost for unit i [\$/h]
CS_i	Number of characteristic curve segments of hydro unit i
E_k	Energy calculated in state k [MWh]
$EENS_t$	Total expected energy not served for system [MWh]

$EENS_{com,t}^{-RSU}$	Expected energy not served for system without rapid-start generation unit allocated with NR and computed up to SRT [MWh]
$EENS_{com,t}^{+RSU}$	Expected energy not served for system with rapid-start generation unit(s) allocated with NR and computed up to SRT [MWh]
$EENS_{k,i,t}^{IL}$	Expected energy not served caused by online unit i followed by IL k at hour t [MWh]
$EENS_{k,i,j,t}^{IL}$	Expected energy not served caused by online units i and j followed by IL k at hour t [MWh]
$EENS_{j,k,i,t}^{IL}$	Expected energy not served caused by online unit i followed by ILs j and k at hour t [MWh]
$EENS_t^O$	Total expected energy not served caused by rapid-start generation units at hour t [MWh]
$EENS_t^{O(f)}$	Total expected energy not served caused by rapid-start generation units when forecast errors are considered at hour t [MWh]
$EENS_{com,t}^{RLT}$	Expected energy not served for system with rapid-start generation unit(s) allocated with NR and computed up to LT [MWh]
$EENS_{i,t}^S$	Expected energy not served caused by online unit i at hour t [MWh]
$EENS_{i,j,t}^S$	Expected energy not served caused by online units i and j at hour t [MWh]
$EENS_{i,j,k,t}^S$	Expected energy not served caused by online units i , j and k at hour t [MWh]
$EENS_t^{IL}$	Total expected energy not served caused by ILs from DSA at hour t [MWh]
$EENS_t^{IL(f)}$	Total expected energy not served caused by ILs from DSA when forecast errors are considered at hour t [MWh]

$EENS_t^S$	Total expected energy not served caused by online units at hour t [MWh]
$EENS_t^{S(f)}$	Total expected energy not served caused by online units when forecast errors are considered at hour t [MWh]
$EENS_{com,t}^{WNR}$	Expected energy not served for system comprises rapid-start generation unit(s) allocated with NR caused by outages of different energy and reserve providers, com [MWh]
$EENS_{com,t}^{ZNR}$	Expected energy not served for system with zero (no) NR allocated to rapid-start generation units. The lead time τ is set to 1-hour lead time (LT), i.e. $\tau = LT$ and starting reliability P_t^{SS} is unity. com is the outage order from different energy and reserve providers [MWh]
EL_i^1 / EL_i^2	Elbow point 1 and 2 of unit i [MW]
$ERIL_t$	Expected energy not served [kWh] is computed based on the reserve allocated to ILs that failed to disconnect at hour t
f	Index used to indicate probability status of forecast error and unit outages
F	Fuel [MBtu]
FCE_t^f	Forecast error for status f at hour t [MW]
FP_t	Forecast error probability with loss of load at hour t
FP_t^0	Forecast error probability with loss of load but without unit outage ($\sum Outage\ MW = 0$)
FP_t^1	Forecast error probability without loss of load but with occurrence of unit outages ($\sum Outage\ MW > 0$)
FP_t^2	Forecast error probability with loss of load and occurrence of unit outages ($\sum Outage\ MW > 0$)

$GUPSF_{i,t}$	A factor used to calculate the share ratio when the UFRs/CBs connected to ILs are maintained by the GSP and the failure to disconnect is not caused by the behaviour of IL owners
$GSIL$	Total number of ILs that fail to disconnect and the GSP is responsible for the maintenance of these UFRs/CBs
$hs_{i,m}$	Slope of segment m for hydro unit i [MW/Hm ³]
i, j, k, h, l	Indices for energy and reserve providers, e.g. generating units
$i_x, i_y, i_z, i_1, i_2, i_3, i_n$	
$IL_1^{offer} / IL_2^{offer} / IL_3^{offer}$	Reserve offered by DSA 1, 2 and 3 [MW]
$IUPSF_{i,t}$	A factor to be calculated when the UFRs/CBs are maintained by ILs or the failure to disconnect is caused by the behaviour of ILs
$J_{i,t}$	Natural inflow to a reservoir for unit i at hour t [Hm ³]
$K_i(\cdot)$	A function uses to determines MW generation of the i^{th} wind turbine
$LC_{i,t}$	Loss of load amount [MW]
LC_t^0	Load curtailment owing to large net forecast error ($f = 0$) without unit outages at hour t [MW]
$LC_{i,t}^f$	Load curtailment with unit i 's outage at hour t when $f \in \{1, 2\}$ [MW]
$Load_t$	System demand at hour t [MW]
$LP_{i,t}$	Loss of load probability
LP_t^0	Loss of load probability owing to large net forecast error ($f = 0$) without unit outages at hour t [MW]
$LP_{i,t}^f$	Loss of load probability with unit i 's outage at hour t when $f \in \{1, 2\}$ [MW]
LT	Lead time of generation units (set to 1 hour) [h]

m	Index for segments of hydro unit's characteristic curve
$MC_{i,s}$	Marginal cost of segment s^{th} of piecewise linear cost curve of unit i [\$/MWh]
$MTTF$	Mean time to failure [h]
NES	Number of unit combination elements in a set
NGT	Total number of open cycle gas turbines
NHY	Total number of hydro power generators
NIL	Total number of DSAs
$NL_i^1 / NL_i^2 / NL_i^3$	No-load cost 1, 2 and 3 of segments of piecewise linear cost curve for unit i [\$/MWh]
NMG	Number of micro-grids allowed to connect to main grid.
NRS	Number of rapid-start units
NWG	Total number of wind turbine generators
ORR_t	10-minute operating reserve requirement at hour t [MW].
p_k	Probability state k the available capacity calculated using COPT
$p_{WTG}(t)$	Probability of failure for WTG at hour t
$P(x)$	Probability function on failure of x WTG units
$P_{i,t}$	MW generation from unit i at hour t [MW]
P_n	n^{th} percentile of the total forecast wind power generation, $P_{Total,t}^W$ at hour t [MW]
$P_{i,t}^h$	MW generation for hydro unit i at hour t [MW]
$P_i^{h,min/max}$	Minimum/maximum power generation of hydro unit i [MW]
$P_i^{min/max}$	Minimum/maximum power generation by unit i [MW]
$P_i^{rs,min/max}$	Rapid-start unit i minimum/maximum capacity [MW]
P_l^{SF}	Failure probability in starting up unit l
P_l^{SS}	Success probability in starting up unit l

$P_{i,t}^W$	MW power output from WTG i at hour t [MW]
$P_i^{W,max}$	Maximum capacity of WTG i [MW]
$P_{Total,t}^W$	Total available MW wind generation at hour t [MW]
P^{WI}	Total capacity of wind turbines [MW]
$P(A)$	Availability probability of generation unit
$P(U)$	Unavailability probability of generation unit
$PC_{i,t}$	Penalty cost for rapid-start unit i which failed to start up during hour t for reserve contribution [\$]
$PCGSP_{i,t}$	Penalty cost for the grid service provider who is responsible for the maintenance of the UFRs/CBs that failed to operate at hour t
$PCIL_{i,t}$	Penalty cost for the i^{th} IL that failed to disconnect when required at hour t
$qS_{i,m}$	Water discharge for hydro unit i at segment m [Hm ³]
$qS_{i,t}^{max}$	Maximum water discharge rate for hydro unit i on segment m [Hm ³]
$q_{i,m}^{sr}$	Water discharge available for hydro unit i in reserve allocation [Hm ³]
$Q_{i,t}$	Water discharge from a reservoir for hydro unit i at hour t [Hm ³]
$Q_i^{min/max}$	Minimum/maximum water discharge's limit for hydro unit i [Hm ³ /h]
$QR_{i,t}$	Water discharge for NR from a reservoir for hydro unit i at hour t [Hm ³]
$R_{i,t}$	MW reserve allocated to unit l at hour t [MW]
$R_{i,t}^h$	MW reserve allocated to hydro unit i at hour t [MW]
R_i^{ils}	Initial overall reserve allocated to DSAs at hour t [MW]

$R_{i,t}^{ils}$	Reserve offer from DSA i at hour t [MW]
$R_{l,t}^{rs}$	NR allocated to offline rapid-start unit l at hour t [MW]
RDR_i	Ramp down rate of unit i [MW/h]
RUR_i	Ramp up rate of unit i [MW/h]
$-RSU$	a system with zero NR allocated to rapid-start unit(s) and computed up to SRT
RLT	a system with NR allocated to rapid-start unit(s) and computed up to LT
$+RSU$	a system with NR allocated to rapid-start unit(s) and computed up to SRT
RSF	a set comprises RSUs which failed to start up for NR contribution during hour t .
$S_{i,t}$	Spillage of water from a reservoir for hydro unit i at hour t [Hm^3]
SF_l	Starting attempts failed to bring unit l in service within a specific timing
SRT	10-minute timing in which a rapid-start unit takes to get synchronised and connected to the network [min]
SS_l	Starting attempts succeeded in bringing unit l in service and connected to the network within a specific timing
$STPC_t$	System total penalty cost at hour t [\$]
t	Time interval [h]
T	Total number of hours in the time period
TCR	Sum of total capacity from energy and reserve providers [MW]
$T_i^{on/off}$	Maximum on/off time of unit i [h]
TH	Total number of thermal units
U	Total number of online generation units
U_l	Unavailability of unit l

$u_{i,t}$	Status of unit i at hour t (1 when committed; 0 otherwise)
$u_{i,t}^h$	Status of hydro unit i at hour t (1 when committed and 0 otherwise)
$u_{i,t}^{ils}$	Status of DSA i at hour t (1 indicates allocated with reserve and 0 otherwise)
$u_{i,t}^{MG}$	Operation status of micro-grid i at hour t (1 indicates selling power, and 0 means operate as a load)
$u_{i,t}^{MG-C}$	Connection status of micro-grid i at hour t (1 indicates grid connected, and 0 means stand-alone)
$u_{i,t}^{rs}$	Status of rapid-start generation unit i at hour t (1 when committed as normal online unit and 0 otherwise)
$U1$	Number of units scheduled at hour t
$U2$	Number of combinations of two units scheduled at hour t
$U3$	Number of combinations of three units scheduled at hour t
Un	Number of combinations of n units scheduled at hour t
US_i	Set of upper stream reservoirs of plant i
$UPSF_{i,t}$	Unit proportional share factor for failed rapid-start unit i at hour t .
V_t	Wind speed at hour t [m/s]
V_i^{CI}	Cut-in wind speed [m/s]
V_i^{CO}	Cut-out wind speed [m/s]
V_i^R	Rated wind speed [m/s]
$VOLL$	Value of lost load [\$/kWh]
w	All possible states for different unit capacity
$W_{i,t}$	Reservoir volume for hydro unit i at hour t [Hm ³]
W_i^0	Initial reservoir's limit for hydro unit i [Hm ³]
$W_i^{min/max}$	Minimum/maximum reservoir's limit for hydro unit i [Hm ³]

W_i^T	Final reservoir's limit for hydro unit i [Hm^3]
$X_{i,t}^{on/off}$	Time duration for on/off state of unit i at hour t [h]

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Chapter 1

Introduction

1.1 Motivation

The electricity power industries throughout the world are undergoing tremendous changes. The changes deviate from one country to another. The reasons of the reformation also differ over the regions. The transformation introduces competition into the electricity power industries.

Conventional thermal generators were the sole electricity generators before the changes. With deregulation of power industries, different types of electricity generators and even demand side can also participate in the energy and reserve markets. Conventional generators are gas turbines, wind turbines, and hydro electric power turbines, etc. The demand side includes the energy users who will interrupt their use of load if needed during contingencies. These services providers possess certain operation characteristics, constraints and reliability. System operators therefore face a challenging task to procure energy and reserve at optimal cost and maintain the system reliability with this generation mix.

1.1.1 From Monopoly to Deregulation in Electric Power Industry

Over the years, generation and sale of electricity to customers are monopolised. Each large generating utility will provide its services in its own territory. The three main components of the electrical system managed by the monopoly utility are generation, transmission and distribution. The monopolized utilities are also known as the Vertically Integrated Utilities (VIU).

In the 1970s to early 1980s, large generators were purchased for energy production [1]. Due to technology constraints during that time, these large generators were able to operate more efficient than those old generators. Fig. 1-1 [1] depicts the sudden rise of generating capacity size over the 50 years time prior to the introduction of gas turbines in 1990s.

Figure 1-1 Power plant construction over a few decades

To reduce the electricity charges to the customers, the electric power industry has to undergo deregulation which introduces competition among the power plants. Creating an open market allows independent power producers (IPP), regardless of their generation capacity size but greater than a specific size in order to compete in the market. Electricity is treated as a commodity traded in the electricity market.

With the deregulation of electric power industry, new entities were born [2, 3]. They are:

Independent System Operator (ISO) - An independent body involves in transmission functions coordination, transmission system maintenance, power flow management. It ensures the overall system reliability and security.

Retailer - An agent provides electric service by submitting energy and ancillary services bids in the electric market on behalf of its customers who are the end-users of electricity. It has to compete in term of price and service.

Market operator or power exchange (PX) - It performs the operation of electricity market trading. Market participants such as Gencos will submit their energy and ancillary services bids to PX to sell their energy and services while Retailers will submit their bids to purchase energy and other services.

The trade of energy and ancillary services are performed in a competitive manner. The market trading schemes may differ depending on the market structure adopted PX. For example, the electricity consumers may choose to purchase electricity from Gencos directly, retailers or even participate in the market.

Large conventional coal-fired generation units need to maintain at idle status while consuming fuel in order to provide a given level of system reliability. Rapid-start units, open-cycle gas-turbines (OCGTs) and hydro electric power generators are able to provide the same service as that provided by these idle large power plants in a short time. In addition, customer loads are able to participate in the market to increase or reduce their consumption when required and when incentives are provided.

1.1.2 Reliability in Electric Power Industry

The reliability of the electric power system is the capability of the generation, transmission and distribution system to provide the customers the electricity they paid for without any failure in the service. Ancillary services are provided to maintain a reliable power system operation and to ensure the degree of quality is served. These services do not come free. In considering ancillary services, the service costs and service values to the system depend on the location. The needs and the flexibility of controlling and monitoring the services are important.

In the restructured electric power industry, the ISO allows different energy services providers to participate in the electricity market, both energy and reserve. These energy providers can be conventional power plants and renewable resources such as wind or solar. The reliability of each generation type deviates from one another. The renewable energy sources are heavily dependent on the environment nature like climate, wind flow and luminance of solar radiation, etc. The reliability of the power system with renewable resources has become a difficult engineering task. The degree of complexity in ancillary services procurement has increased.

Operating reserve enables the system to raise the generation level when contingencies such as demand shortfall or generation outage occurred. At any time, the system must be able to react to the unexpected events and maintain the balance between generation supply and system demand. Procurement of reserve and its applications are necessary to meet the electric system reliability requirement.

The operating reserve requirement (ORR) comprises spinning reserve (SR) and non-spinning reserve (NR). NR is also known as supplemental or standing reserve in some countries. The amount of ORR procured and the quality of the reserve have a direct impact on the reliability of the power system. The quality of reserve depends on the resource type.

It is expensive to maintain the system at a healthy reliability level. If the benefit on the short fall of generation is more attractive than the cost to sustain a reliable level, the customer load may have to be interrupted by the ISO, rather than paying for reserve.

1.2 Contributions

A modelling of the market clearing engine taking into consideration the operating reliability of each individual generating unit in the objective function is presented.

This is accomplished by computing the availability of the unit for the expected energy not served (EENS). The interrupted loads (ILs) that offer their bids in the reserve market have also been modelled considering their operating reliability. The reliability of ILs refers to how reliable the load could disconnect from the transmission grid when their service is called for. The effect of value of lost load (VOLL) on system reliability and economics has also been traversed.

In this work, the thermal generation units refer to the coal-fired steam generators while open-cycle gas turbines (OCGTs) refer to gas-fired units which are not stream units. Other than modelling the thermal units and ILs to study the power system economics and reliability, a generation mix of OCGTs, wind turbines, and hydro generation units are also considered in this work. For hydro units, the river flow networks, the reservoir contents and the spillage are also modelled. The unit commitment (UC) process is formulated by Mixed Integer Programming (MIP), which is coded using General Arithmetic Modelling System (GAMS) commercial software and solved by the CPLEX 10.2 solver. The pre- and post-processing modules of UC are programmed in MATLAB on an Intel Core2 Duo CPU E7500, 2.93 GHz and 3 GB Ram.

The starting reliability of rapid-start units such as OCGTs is integrated in the objective function of the UC problem. A joint probability distribution approach is adopted to incorporate the starting reliability with the unit operating probability. A table of probability events is formed to synthesize the unit event probability. A new availability index is calculated from the table and a methodology is proposed to model the EENS caused by OCGTs that are allocated with non-spinning reserve (NR). The time period when OCGT is initiated to start up for NR contribution till it successfully connects to the network is considered. This work has shown how this short duration of start up time can be represented pictorially in term of the EENS values. The total cost at optimal reliability for the system with starting reliability is then compared with the system without considering the starting reliability. A cost/benefit analysis is used to determine the optimal cost.

A generation mix is modelled to reflect the present and future trends in the electricity supply industry. Other than conventional hydro generation units, this work has also considered wind energy generation. The primary resource for wind energy generation is wind flow which is sporadic in nature. The forecast of the wind speed is never exact. A methodology which considers the wind forecast error and load forecast error in the EENS formulation through determination of probabilities using the normal distribution approach is proposed. The impact of wind energy penetration on the generation system is then studied. Results of the system reliability, total cost for energy and reserve procurement, and reserve allocation with wind energy integration are presented.

To summarise, the unique contributions of this research works are:

- ❖ A UC objective function is formulated to incorporate the energy/reserve providers and simultaneous scheduling of energy and reserve.
- ❖ A practical methodology to formulate the ILs reliability based on their types of power supply sources is proposed.
- ❖ An in-depth study on the impact of ILs on system economics and reliability with a curve showing the effects are presented. This has never been well discussed in the literature. It provides a guide for system operators to allocate reserve to ILs and also for demand sides to manage their loads for better profit in the electricity market.
- ❖ A technique to incorporate the starting probability and operating reliability of rapid-start units is presented.
- ❖ A technique to integrate load and wind power forecast errors and represent them in terms of EENS is presented.
- ❖ An EENS plot that illustrates how EENS is contributed by different services providers is presented.
- ❖ Penalty cost functions are formulated to penalize those noncompliance service providers and to improve the system reliability.

1.3 Organisation of the Thesis

In this thesis, the objective function that comprises energy, reserve and EENS costs is explicitly illustrated. A probabilistic approach using an initial deterministic reserve criterion is adopted. The EENS formulation which incorporates start up failures of rapid start units, and the modelling of wind energy generation which considers wind forecast error due to sporadic wind flow are presented.

Chapter 1 introduces the motivation of this research. Deregulation, competition and reliability of electricity supply system are briefly described. The objectives and contributions of this research work are also presented.

Chapter 2 discusses the operating reserve of the electricity supply system. A review of the relevant literature on reliability, operating reserve, spinning and non-spinning reserve, cost/benefit analysis, demand side management (DSM), types of rapid-start generation and wind energy penetration is summarised.

Chapter 3 presents how the 10-minute operating reserve is determined and delineates the reserve procurement procedure. A small generation system with reserve contribution from DSM is modelled. The effects of ILs on the conventional electric power system are presented. A penalty calculation that penalises ILs which failed to disconnect from the system when requested is proposed.

Chapter 4 models the rapid start units, OCGTs. Their characteristic of high failure probability during start up is studied and a technique to model the starting reliability and the operating reliability is proposed. A methodology to formulate the EENS contributed from these units is presented. The EENS terms used in the analytical calculation are also pictorially presented. A study which comprises OCGTs with different operating and starting reliability is performed. A penalty calculation that penalises OCGTs which failed to start up for reserve contribution is proposed.

Chapter 5 presents the penetration study of renewable energy. Hydro electric power generation is modelled and studied. The water flow networks, reservoir contents and spillage are considered in the modelling. A methodology which integrates the load demand and wind forecast errors in the EENS formulation through the determination of probabilities using the normal distribution approach is proposed. The modelling of the wind turbines is studied and presented. The effect of wind energy in the conventional generation system and its impact on power system economics and reliability are scrutinised.

Lastly, the conclusions of this research work and the recommendations for future works are presented in Chapter 6.

Chapter 2

Literature Review

Since late 1980s, the electric power industry is moving toward a deregulated framework globally. In this era, the ISO faces a challenging problem in securing sufficient reserve for power system operation. The ISO would strive to procure a certain amount of generation capacity as 10-minute operating reserve to ensure that the power system is able to withstand unforeseen outages of system components or sudden load increase, without having to resort to load shedding. In order to attend to the need of this research on the effect of the electric power system with competition introduced, the background literature such as deregulation of the electric power industry, system reliability, operating reserve, cost/benefit analysis, demand side management and rapid-start generation types are discussed. Moreover, the penetration of renewable energy, such as hydro and wind energy, into the conventional power system has also been reviewed.

2.1 Deregulation in Electric Power Industry

A process of transition and restructuring of the electric power system occurred in the late 1980s. The power systems were either in the form of corporation under government-owned corporation or privatisation under privately held corporation. Fig. 2-1 [4] shows the final form of competitive electricity market when all the customers can choose their supplier. Only the transmission and distribution networks remain as monopoly functions.

Figure 2-1 Competition in electric power industry

The deregulation process in the United States (US) was effectively initiated in the year 1978 [5]. The idea of competition in generators was introduced. However, generators and IPPs were only to sell their production to local regulated investor-owned utilities [6]. Wheeling services to the non-utility generators through electricity transmission were opened up [7, 8] at that time.

In the early 1988, the United Kingdom (UK) was practising nationalised electricity industry [9–11]. In Australia, the provision of electricity services was under the government [12]. In May 1991, a restructuring of the utilities was initiated [13]. In 1993, there was a restructuring of electricity industry in South Australia followed by corporatisation in 1995 [14]. In 2009, the NEMMCO was replaced by Australian Energy Market Operator (AEMO) that was established to manage the NEM and gas market [15]. In New Zealand, the monopoly powers were limited and promoting the development of competitive markets was legislated in 1986 [12]. The energy market was officially opened up to competition in 1992 [16]. In France, the operation and control of electricity were run by Electricité de France (EDF) since 1946 [17]. In 2005, the Energy Regulation Commission (CRE) had listed 23 active alternative

suppliers to compete with EDF and the other three power generation companies in the electricity wholesale market [18].

Most of the power system assets in Singapore were owned by the government through its investment arm, Temasek Holdings before 1995 [19]. Since 1995, these government-owned power system assets have been structured for commercialisation following privatisation. A New Electricity Market (NEM¹), which represented a fully competitive wholesale and retail electricity markets, came into operation in 1998. The process of deregulation has been reviewed over the years and by early 2003, the National Electricity Market of Singapore (NEMS) was launched. The Energy Market Authority (EMA) is responsible for regulating the electricity sector and Energy Market Company (EMC) licensed by EMA operates and administers the wholesale market. In 2008, Temasek Holdings transferred 100% of its share of three large power plants in Singapore and sold them to China HuaNeng Group, Lion Power from Japan and YTL Power International Berhad from Malaysia. This began a fully privatisation of electric generation assets in Singapore.

2.2 Reliability in Electric Power Systems

From electric power generation to distribution of electricity, numerous types of power system components connect to form an electric network. Generally, a power system comprises thousands of static items and dynamic equipments. The failure in operations of any of these components is unpredictable. Any outage may lead to severe loss of load and affect the economics of the area.

Under deregulation of the electric power industry, the ISO needs to procure a certain amount of generation capacity as reserve to ensure the reliability and stability of the power system. The necessity of the reserve procurement is to alleviate the probability of failure to carry the load and the effect on load loss in power systems.

The stochastic nature of unit outages when determining the spinning reserve (SR) requirements was introduced by Aristine et al [20]. With probabilistic nature of system behaviour and component failure, a number of research works were carried out to counter these unpredictable occurrences through an appropriate reserve determination. A common probabilistic technique among the recent works is the determination of reserve assessment using a three-state well-being model [21-27]. Other than [27] and [28] which incorporate the n-1 deterministic criterion, different system operating states are defined for the calculated probability indices to match onto the states which the system is supposed to be in. These probability indices are generally meaningless to the system operator without operating states declared.

For most of the works described above, after the Unit Commitment (UC) is performed, the number of units committed has to satisfy a specific risk or an acceptable system health or both. The risk level is computed with the lead time (LT) which is defined as the period of time that generation cannot be replaced when the probability of the committed generation just satisfying or failing to satisfy the expected demand [29]. With the increase of the LT, the probability of bringing additional units into service will decline. Thus, a sufficient number of generating units has to be committed in order to maintain a healthy state or satisfying the risk criteria.

The unreliability of the unit [20, 29] is an approximate probability value given by

$$P(\text{unit failed during lead time}) = 1 - e^{-\lambda T} = 1 - e^{\frac{-LT}{MTTF}} \quad (2-1)$$

This probability of a unit failed during the LT is also known as the outage replacement rate [20, 29]. It is evaluated from the traditional PJM method [20], where the exponential distribution mean time to failure (MTTF) is the reciprocal of the failure rate λ , i.e.,

$$MTTF = \int_0^{\infty} \lambda t e^{-\lambda t} dt = \frac{1}{\lambda} \quad (2-2)$$

The outage replacement rate is to be distinguished from the forced outage rate, where the latter is the computation of long term probability of a given state of a power system.

After deregulation, different techniques have been proposed to improve the power system reliability calculation. These include the state selection technique which was proposed to evaluate the occurrence probability of outage states [30], a combination of evolution strategies and particle swarm optimisation [31, 32] for power system evaluation.

The reliability assessment in the electric power industry has been growing more complex with the deregulation and privatisation of the industry. An integrated approach to reliability invoking the electric system component reliability and the system reliability has been traversed [33].

The reliability of electric power system is to provide a static system condition to meet the system demand with available facilities. It is also referred to the capability in responding to the perturbations of the electric power system at any point in time. This is the definition of reliability to ISO. However, from the customers' perspective, the reliability of an electric power system is the number and duration of interruptions experienced, as well as the loss of interruption incurred. Surveys on the available estimation techniques of the customers' interruption costs and failure experiences are performed [34, 35]. A method to compute the value of lost load (VOLL) [36] was developed based on the survey results. The VOLL is defined as the cost imposed by involuntary load curtailment of each additional MW of energy [37]. The developed method generally has a problem as it relies on outage durations which are unknown before hand and interruption durations do differ from past occurrences.

The cost of power system reliability is an important issue. In deregulated environment, this cost is to be minimised. The reliability cost computed based on the stochastic optimisation considering loss of load expectation (LOLE) and expected energy not served (EENS) of long term security-constraint unit commitment is presented [38]. This is followed by a new method for EENS computation with the generating unit reliability explicitly expressed in the formulation of EENS [39].

A poor reliability in electric power industry means higher chances of getting blackout or loss of electricity supply for a time period. This will affect the economic growth in the region since investors will lose confidence on setting up businesses in these regions. Therefore, this research work has delved into the study of different generation types and probabilities of outages of reserve providers which effect electric power economics and reliability. These will be illustrated in the next three chapters of the thesis.

2.3 Operating Reserve in Electric Power Industry

Electricity cannot be stored or saved economically. The electric power supply must always be equal to the system demand. This balance has to be constantly monitored by ISO. The system must be capable of responding to any unforeseen events. In order to do all these, the operating reserve requirement (ORR) needs to provide additional generation margins within a response time ranging from few seconds to several minutes, to ensure that the supply-demand balance is achieved seamlessly.

Operating reserves are normally categorised based on the response time of the reserve sources needed. This categorisation deviates over regions. Table 2-1 summarises the different types of reserves and their sources over different regions.

Table 2-1 Operating reserve types and sources

ISO	Reserve Type	Sources
Trans-power [40]	Instantaneous Reserve	Spinning and synchronised generators.
	Stand-by Reserve	Off-line generating units, and interruptible demand.
EMA [41]	Primary Reserve	Spinning and synchronised generators, and interruptible load.
	Secondary Reserve	
	Contingency Reserve	
AEMO [42]	Fast Raise and Fast Lower	Generator governor response, load shedding, rapid-start generator, and rapid unit unloading.
	Slow Raise and Slow Lower	
	Delayed Raise and Delayed Lower	
AESO [43]	Spinning Reserve	Spinning and synchronised generators and boundary entities.
	Supplement Reserve	Generators, loads and boundary entities.
CAISO [44]	Spinning Reserve	Spinning and synchronised generators, system resources from external imports, and system generating units.
	Non-Spinning Reserve	Generating units, curtailable loads, system resources from external imports, and system generating units.
IESO [45]	10-Minute Spinning Reserve	Dispatchable generators and loads
	10-Minute Non-Spinning Reserve	Dispatchable generators and loads, and boundary entities.
	30-Minute Operating Reserve	
National Grid [46]	Fast Reserve	Spinning and synchronised generators and loads.
	Short Term Operating Reserve (STOR)	Standby generators and load demand.
NYISO [47]	10-Minute Spinning Reserve	Spinning and synchronised generators and demand side resources (interruptible/ and dispatchable load.)
	30-Minute Spinning Reserve	
	10-Minute Non-Spinning Reserve	Quick-start units (jet engine gas turbines), and demand side resources.
	30-Minute Non-Spinning Reserve	Generators, and demand side resources.
PJM [48]	Synchronised Reserve – Tier 1	Spinning and synchronised generators and loads
	Synchronised Reserve – Tier 1	

Traditional determination of the needed reserve, particularly on spinning reserve (SR), is a deterministic criterion by setting the reserve requirement equal to the loss of the most heavily loaded unit, a given percentage of forecasted peak demand in a given period of time or a combination of both [49]. These methods are generally known as a rule of thumb method. This approach does not assess the actual system risk and does not respond to or reflect the stochastic nature behaviour and component failures. In recent years, the probabilistic technique based on a system risk level is used and attracts considerable attention.

System fuel costs are minimised through shutting down and starting up of units in the UC program [50]. The SR is determined deterministically and the ramp rate of the generating units has not been considered. An approach by incorporating the units with multi-layer states in COPT for SR studies has been scrutinised [51]. However, the effects of this incorporation deviate among systems.

In-depth studies on optimal scheduling of reserve have been performed [52-66] over the past years. In most of these works, the probabilistic approach is applied on the operation of generation units. The start up failure reliability is normally neglected. Ortega-Vazquez et al [64] have studied the SR optimisation process when generators failed to synchronise. The results show that a large amount of capacity is synchronised to meet huge demand requirement. More units are started up during periods of heavy demand. The incorporation of unit failure to synchronise resulted in more reserve procured and reduced the EENS value. It does not take into account the start up failures of OCGTs and hydro units which have been allocated with NR and these units failed to provide energy contribution during a contingency.

Different techniques have been improvised to determine optimal reserve in electric power systems [65-68]. Deregulation has changed the traditional power generation business. The objective of Gencos is to maximise their profit. Reference [67] presents a profit-based UC problem to accomplish the objective of Gencos but it does

not take into consideration of competition among the Gencos. The system reliability has been neglected totally. In [68], the unit reliability has not been considered as well.

In a fully deregulated electric power industry, the electricity consumers are able to choose their electricity suppliers. The choice is between the price and reliability of electricity supply. Consumers with a higher VOLL may consider going for higher reliability. This implies higher electricity prices. A technique to plan and operate the power system based on the choice of reliability by consumers has been developed using a risk index to express the load point reliability [69]. However, the demand side management and rapid-start unit contributions to reserve allocation have not been studied.

Evolutionary Algorithm (EA) is a problem solving technique implemented based on evolutionary theory principle. In the past few years, there was an increase in research based on EA in the field of power systems [70]. EA has been extensively used to solve UC problems [71-76]. In [71], an evolutionary programming (EP) technique in which populations of contending solutions are evolved through random changes, competitions and selection has been proposed. The work shows that the technique is able to provide satisfactory performance. The EP which is guided by heuristics is used to solve UC and to determine SR in large scale power systems [72]. A Priority List method is employed to determine an initial population in their work. It shows that the UC for profit maximisation is better compared to traditional UC algorithms. An EA which combines a local search algorithm and non-dominated sorting genetic algorithm is proposed in a recent work [76]. It concludes that their proposed methodology is able to generate multiple Pareto-optimal solutions in a single simulation run. However, unit reliability has not been discussed in these works.

As discussed, the structure of reserve procurement deviates over regions and countries. The types of reserve service providers have also been categorised into different classes. This depends on their response time and reliability of providing the service. The role of reserves is to maintain system security and reliability. A 10-

minute ORR is structured for the reserve procurement in this research work. It comprises SR from online generation units and demand side management, and NR from offline generation units. The effect of these different reserve providers on the power system economics and reliability is studied. This work uses the basic probabilistic technique to calculate unit outages, and failures to start up units for reserve and OR contribution using a probabilistic approach based on an initial deterministic reserve criterion method.

2.4 Cost/Benefit Analysis in Electric Power Industry

A cost/benefit analysis (CBA) is basically used to make decision on the worth of a scheme to weigh up the advantages and disadvantages of public policy and has been extensively employed in 1978 [77, 78]. The deregulation of electric power industry in late 1980s, therefore, has triggered researchers to delve into CBA applications in the electric power industry.

The ISO has to dispatch energy and allocate reserve services at a least combined schedule cost. The value of the EENS cost computed has to be reasonable and acceptable. Thus, the CBA approach is adopted to obtain the optimal cost in [52, 53, 59, 62, 64, 86]. Although the rule of thumb method which determines the reserve is simple to implement, the social welfare of the OR cannot be maximised.

The determination of ORR has to consider generation unit characteristic, outage rate and reserve cost. A suitable reserve amount can be estimated based on the trade-off between additional reliability and cost of lost load. A combined deterministic and stochastic criterion has been traversed to assess the OR [80]. In [81], a methodology to clear the energy and reserve markets simultaneously and to determine the reserve requirement using a CBA is proposed. The method has neglected the use of a termination criterion such as a risk index or a probability state etc. Thus, an industry sector with low VOLL [82, 83] may have a low reserve amount procured as there is no specified criterion for the reserve amount. If a contingency occurs, without

sufficient reserve, blackout may occur. This affects the confidence of investors in doing business in the area.

The difference between power system planning and operation is dominated by the accuracy of security values and uncertainties of power systems. As the operation analysis is taken at a time closer to the actual events, a higher accuracy is expected. Reference [84] presented a method to compute the value of security for an electric power system based on a CBA. The study has shown that the outage cost is dominated by hidden failures and the consequent sympathetic tripping in the electric power system.

Competition introduced in the electric power industry tends to force utilities to accept more risks. This is because the Gencos are not obliged to supply energy and reserve to meet system demand at a specified reserve level. A number of works on the study of electric power system reliability on the basis of CBA have been performed [85, 86].

The CBA has been used in planning process in several countries such as Norway, Sweden, Finland, Canada and Brazil [83]. The approach has been adopted at the very beginning state of system planning to optimise power system reliability [87]. A method to achieve the optimum reliability in power systems using CBA for reliability planning is presented in [88, 89]. The objective is to plan and improve a transmission network with a suitable reliability.

In electric power production, especially from conventional coal-fired generators, there is a significant greenhouse effect on the environment resulting in global warming. The power transmission sector produces negative effect to the environment too. This social-environmental damage will incur an external cost [90]. In [91], a CBA process considering these external costs in the coordination of electric power system expansion planning is presented.

The usage of traditional deterministic criteria has failed to consider the stochastic system components outages. The utility costs of providing the required reliability level is therefore independent of the customer interruption costs. Effects such as failures of breakers, transformer and bus-bars etc, are considered in [92] in the study of additional generation using CBA.

There will be a slight reduction in conventional generating sources in the future due to their environmental damage and the penetration of new energy sources. A study on whether a deterministic or a probabilistic method with CBA is more efficient for SR procurement considering wind power penetration is performed in [93]. Reference [94] studied the application of CBA on the sizing of energy-storage system for electric power systems with wind energy penetration. Other than the application of CBA in a renewable energy system, CBA is also used in the under-frequency load shedding scheme [95], to determine the load shedding requirement and to reduce the SR amount.

In a competitive environment, electric utilities are being pressurised to reduce energy and reserve price while the needed reliability is pressurising them to spend more. To balance between cost and benefit, a CBA can be used. This research work has adopted CBA to evaluate the optimal total cost throughout as illustrated in the next few chapters of the thesis.

2.5 Demand Side Management

In 1974, International Energy Agency (IEA) was established [96] and the Demand Side Management (DSM) programme was developed in 1993. The objective is to create a more reliable and sustainable energy supply system globally. This is then followed by a project on implementing Demand Side Bidding (DSB) [97]. The DSB electricity consumers will receive incentives for making short-term changes such as load interruption from their normal electricity consumption profile. The customer loads that offer for this DSB are generally known as interruptible loads (ILs).

The responsive demand such as ILs is likely to be large consumers or an aggregation of smaller loads from a number of sites. A generic approach which quantifies the level of responsiveness among domestic participating consumers in this DSM program is presented in [98].

In the Singapore electric power system, the ILs option allows electricity consumers to compete in the reserve market [99, 100]. This has lightened the pressure on power system operators as the market rule previously only allows reserve allocation to Gencos. To provide this service, a load must be able to reduce at least 0.1 MW voluntarily when needed. The under-frequency relay (UFR) has to be installed for consumers qualified in the provision of primary and secondary reserve as in Table 2-1.

Reference [101] presents a short review on ILs carrying capability in a generation system. The application of well-being indices is used to evaluate optimum interruptible load carrying capacity via an energy based approach [102].

The work of [102] was extended in [103] to calculate the total societal cost which comprises system operating cost and customer interruption cost and it incorporates load management. In [104], a study on the uncertainty of activation time of IL affecting the SR procurement is performed. The work only performed a single-hour analysis and could not reflect the system performance of coupling constraints over a longer study horizon.

ILs are energy consumers and serve as a provision of reserve from DSM. The probabilistic technique [52] in procuring the SR as a function of loss of load probability (LOLP) and EENS has been synthesised [105, 106]. As shown in their works, the incorporation of ILs in the market operation has improved the system security and integrity. Reference [107] has shown that component reliability

parameters have an impact on the system reserve requirement using a reliability related reserve criterion.

In an electricity wholesale market, the retailer that entered into contracts with fixed rates will expose to huge risks when the price spikes. Therefore, an option fee and an exercise fee proportional to the energy not served will be given to consumers who disconnected their supply during emergencies [108]. This allows the system operator to have more choice of reserve options in OR allocation. The exercise fees incurred for demand side vary geographically. Loads that are located at a congested transmission node, both commercial and industrial, usually have a higher value than that located at residential nodes. Hence in [109], a technique to compute IL participation based on geographical location is presented. The study shows that the system with high outage rates and high exercise fees, its security will deteriorate. The demand side participating in the reserve market shall be covered with incentives [110].

In [111], ILs are treated as generating units in the model. The work shows that when VOLL increases, LOLP also increases. It contradicts the concept that a higher VOLL will result in a higher reserve procurement and a lower LOLP index. In [112] offering price of ILs is sensitive only when the demand level is at its peak value.

In chapter 3 of this thesis, a small generating unit system will be modelled with demand side agents to study how various costs are being affected. It also scrutinises reserve allocation among generators and ILs and their influence on EENS.

2.6 Rapid-Start Generators

Rapid-start generators, both gas and hydro, are able to start up in minutes and are allowed to participate in the 10-minute OR, particularly the non-spinning reserve.

2.6.1 Gas Turbines

The starting and stopping of gas turbines can be performed easily and rapidly. It takes about 2 minutes between start initiation and synchronisation, and some 3 minutes after start initiation to carry full load [113]. They have high ramp rates and are suitable for rapid deployment. All these characteristics favour electric power generation for immediate, peak loads and some base loads. Although the capital cost for gas turbines is low, they normally burn natural gas which is relatively more expensive [114] than coal. This results in economic detriment in scheduling gas turbines operating alone for base or intermediate load.

The gas turbines can operate in open cycle mode known as OCGTs or combined cycle mode known as CCGTs [115]. When operating as CCGT, there is a big reduction of CO₂, nitrogen oxide (NO_x) and SO₂ emission [116]. The CCGTs have been extensively used for base load and cyclic operation by the system operators over the world. When the gas turbines are operated in OCGT mode, they are usually deployed for standby or peak load shaving. With short start up time, they are also called upon during a major plant outage. Progress in market liberalisation of gas industries and development of national regulatory authorities [117] which make the gas cheaper and enable OCGTs to be deployed more intensively in energy and reserve scheduling.

The reliability and performance of gas turbines are indispensable when planning OCGTs in energy scheduling and reserve allocation. This reliability factor has been neglected in a recent work [118] that studied on the operation of CCGTs and OCGTs. This work together with [119] has not considered the starting reliability in their studies. A significant start up failure rate in the gas turbines [120, 121] has made the starting reliability a desideratum in energy scheduling and particularly in reserve allocation. The results from these works show that unit failures are most likely to occur during starting sequence. Units may experience starting failure with one unit failed after another unit within 5- and 10-minute time intervals during start up. This

failure bunching effect has appeared in Singapore during the electricity supply interruption in June 2004 [122].

Performance and reliability are used to measure the value of gas turbines. The starting reliability is defined as the expected likelihood that a generating unit can successfully start on demand and/or within a given time period [123]. The formulation of starting reliability differs from one program to another.

When a rapid-start unit is called in for energy and reserve services, the time between initiation and synchronisation is short. This is particularly true for reserve contribution. The rapid-start unit will either fail to start or proceed into operation. This behaviour has been discussed in [124-127].

2.6.2 Hydro Generation Units

The power generated from the hydro unit depends on the reservoir content and the water flow at the place where the power plant is located. Ideally, the volume of water used to generate a MW of power by a hydro plant can be used to generate another MW of power in the same plant (with pump storage facilities) or in another plant.

Both the hydro and gas turbine units exhibit high ramp rate characteristic. Hydro generators are not involved in thermal heating process and they can be initiated to synchronise at a speed faster than gas turbines [128-130]. The hydro units are generally used to generate energy for intermittent load sharing and peak load shaving.

A malfunction in the control equipment for a power plant will lead to unavailability costs. Reference [131] interviewed major power producers and hydro plants in Sweden. The objective is to identify a number of aspects which contribute to start up costs. The investigation has shown that the cost to start up hydro units is high due to these contributing factors. The start up cost will increase with the size of the unit as presented in [132].

Thermal units depend on fuel and can operate to produce maximum capacity while hydro units depend on water flow, reservoir content and environment factors which are much complex. A number of research studies on scheduling, UC and reserve determination for systems with hydro plants were conducted [133-138].

Although there are numerous research works on UC scheduling and reserve requirement determination with rapid-start units, studies on start up failure of these units during reserve contribution are seldom done. This research work proposes a pellucid statistical technique in modelling start up failure probabilities of rapid-start units for energy scheduling and reserve allocation. These probabilities are explicitly formulated and manifested in Chapter 4 of this thesis.

2.7 Wind Energy Penetration

In recent years, renewable energy sources have grown rapidly. The main cause for this increase is the growing concern of global warming issues and the environment impact resulted from the use of conventional energy systems, especially those with coal-fired steam turbines. Wind energy is the most successful renewable source that has been introduced in the existing power system [139-142]. With this growth of wind power over the regions, the cost per kilowatt of wind power is significantly reduced.

The total system cost with wind energy integration is significantly reduced due to cost saving in fuel cost [143]. However, wind energy production relies on geographical wind flow. Therefore, it is necessary to consider wind flow uncertainties when integrating wind power into the existing power system [144].

Wind speed forecasting has become an important tool for wind energy integration. The auto-regressive moving average (ARMA) time-series model is one of the most popular forecasting method used [145-150]. In [151], a comparison of different

forecasting methods is performed. The results show that forecast errors exist regardless of any methodologies used.

Wind forecasts are not 100% reliable. The forecast error can be modelled as stochastic variables with a mean and a standard deviation [152-155] and is used to obtain deviation between supply and demand, and estimation of SR requirements for systems with wind energy penetration. To surmount the incomplete formulation of the optimisation problem on wind energy penetration, references [156-158] have explicitly included the various wind turbine constraints in their objective functions. However, wind forecasted errors and failure rates of wind turbines which will affect both economics and system reliability have not been studied in these works.

System reliability is one of the major issues with wind energy penetration, because wind energy is intermittent. Reference [159] has shown that wind farm generation requires almost nine times the MW capacity of a conventional unit to replace that unit. In [160], the OR is determined through deterministic approach. It has concluded that high availability of wind generation units results in low reliability indices for low wind power penetration, whereas the availability of wind generation units is overshadowed by energy fluctuations during high wind power penetration.

The stochastic nature of wind alters the UC and dispatch problem. Many UC studies with wind energy penetration were conducted over the past few decades [161-170]. A number of these works neglected wind generation forecast errors in the study.

It is difficult to predict the forthcoming wind power generation and the error increases with the forecast time horizon. The UC risk tends to increase with wind energy integration [166]. Reference [167] has illustrated that base load units are not affected by wind power generation uncertainties, and the rapid-start units will be scheduled less but allocated with non-spinning reserve. With wind energy integration, the impact of conventional unit ramping constraints, DSM, and reserve procurement techniques has been performed [168-170].

However, to the best knowledge of the author, comparisons of system reliability, total cost and reserve procurement among different power system configurations with and without wind energy penetration are still lacking in the literature. In this thesis, the effects on power system reliability, total cost and reserve procurement are scrutinised considering the worst forecast error scenario. A methodology is proposed to formulate the EENS incorporating the net forecast error on load and wind power generation. A comparison of the results among different system configurations with wind power integration is performed.

2.8 Summary

An overview of the technical requirements for OR adopted globally is presented. Different methodologies and techniques used for reserve procurement are illustrated. To balance between the system total cost and social welfare, the cost/benefit analysis is introduced. The demand side participation in the electricity market has also been shown. The deployment of rapid-start units such as gas turbines and hydro units are discussed. The penetration of wind energy into a conventional electric power system has also been reviewed.

Chapter 3

Conventional Thermal System Studies with Demand Side Participation

3.1 Introduction

In any electric power system, methodologies are implemented to schedule energy and allocate reserve. The Gencos would like to maximise their profit based on their available assets. The ISO would like to minimise the overall costs incurred for energy and ancillary services procurement based on the bids submitted by energy and ancillary services providers.

In Singapore, the UFRs will trip instantly when the system frequency falls below 49.4 Hz or when the system frequency falls to or below 49.7 Hz for 30 s [100]. This chapter studies the power system economics and reliabilities when ILs from demand side is incorporated. A methodology to model IL reliability for the EENS formulation is presented. A penalty cost is imposed on the ILs and the grid service providers (GSPs). They are responsible for the maintenance of UFRs/CBs which control the disconnection of ILs. IL owners and/or GSPs who fail to disconnect the load manually or automatically are penalised.

A framework for a conventional thermal unit system incorporating demand side management for reserve contribution is presented in this chapter. In this thesis, conventional thermal units refer to coal-fired power generators. The objective function has included the demand side bids on reserve and the EENS cost of each time interval. The energy and reserve are procured simultaneously by having the energy and reserve market clearing engine modelled in a single problem. All UC processes in this thesis are modelled by MIP [171] which is coded using General Algebraic Modelling System (GAMS) and are solved by the solver CPLEX 10.2

[172]. The pre- and post-processing of UC are programmed with MATLAB programming [173]. The cost/benefit analysis approach is used to obtain the optimal system total cost. The simulation results are presented together with the UC solution.

3.2 Modelling of Energy and Reserve Providers

A market structure is established in this work whereby Gencos submit bids on energy and reserve while the demand side submits bids on reserve. The objective function formulated will schedule energy and allocate reserve among the various participating sources, to achieve a minimum system total cost for a study period of 24 hours.

3.2.1 Modelling of Conventional Thermal Units

The operation of conventional thermal units, excluding gas turbines, involves in a vapour and liquid cycle known as Rankine Cycle. Once the thermal unit is decommitted after operation, to commit this unit again, the temperature and pressure have to increase back to their operating values. This incurs cost as the process requires the combustion of fuel for steam generation. The cost to start up the unit will increase as it has been decommitted for some times, as depicted in Fig. 3-1.

The start up cost of a thermal unit [49] is given as

$$cr_i^{SU} = cr_i^{fixed} + F \cdot cr_i^c \left(1 - e^{-\frac{t}{\Gamma}} \right) \quad (3-1)$$

where

cr_i^{SU}	start up cost for unit i [\$]
cr_i^{fixed}	fixed cost for unit i [\$]
F	fuel [MBtu]
cr_i^c	cold-start cost for unit i [\$/MBtu]
t	time duration unit i has been decommitted [h]

- i unit number
- Γ time constant for thermal unit i [h].

Figure 3-1 Time-dependent start up cost

As the cost of electrical power generation is directly proportion to the amount of fuel consumed, the relations between the production cost and the MW generation of a thermal unit can be represented using a piecewise linear cost curve as in Fig. 3-2. This curve is the basis of measurements obtained when the thermal unit operates at different output levels. Each operating stage is represented as a segment in the curve. The change of the production cost with the change of MW production from the thermal unit gives the value of marginal cost as in Fig. 3-3. The marginal cost curve is constant for each segment. The determination of the cost per MW production from this curve is shown as

$$\begin{aligned}
 P_i^{min} \leq P_{i,t} < EL_i^1 &\Rightarrow MC_{i,1} \\
 EL_i^1 \leq P_{i,t} < EL_i^2 &\Rightarrow MC_{i,2} \\
 EL_i^2 \leq P_{i,t} \leq P_i^{max} &\Rightarrow MC_{i,3}
 \end{aligned} \tag{3-2}$$

where

$$P_{i,t} \quad \text{MW generation from unit } i \text{ at hour } t \text{ [MW]}$$

P_i^{min}	minimum power generation by unit i [MW]
P_i^{max}	maximum power generation by unit i [MW]
EL_i^1 / EL_i^2	elbow point 1 and 2 of unit i [MW]
$MC_{i,s}$	marginal cost of the s segment of piecewise linear cost curve for unit i [\$/MWh].

The cost per MW production is the same when the generation falls within a segment. If the generated MW is equal to the elbow point value, the marginal cost of the next segment will be used instead. This is because the marginal cost is usually considers as the cost of next MW production rather than the previous MW production.

The production cost of a thermal unit is, therefore, the sum of a no-load cost (NL) and the cost of $P_{i,t} \cdot MC_{i,s}$ where $MC_{i,s}$ depends on the segment the unit is operating in. For a thermal unit with three segments of piecewise linear cost curve, they comprise no-load costs of three different values as illustrated in Fig. 3-2. The segment of MW that maps to the specific marginal cost is shown in Fig. 3-3.

Figure 3-2 Piecewise linear cost curve of a thermal unit at different MW generation

Figure 3-3 Piecewise constant marginal cost curve

The first no-load cost (NL_i^1) is determined through measurements of running the unit at zero MW output generation. The second no-load cost is calculated based on the first no-load cost value, while the third no-load cost is based on the computed second no-load cost value as shown below:

$$NL_i^2 = EL_i^1 (MC_{i,1} - MC_{i,2}) + NL_i^1 \quad (3-3)$$

$$NL_i^3 = EL_i^2 (MC_{i,2} - MC_{i,3}) + NL_i^2 \quad (3-4)$$

where

$NL_i^1 / NL_i^2 / NL_i^3$ no-load cost 1, 2 and 3 of the segments of piecewise linear cost curve for unit i [\$].

With all these parameters determined, the production cost of a thermal unit is then formulated based on Fig. 3-2 and equation (3-2) as

$$C_i^E(P_{i,t}, MC_{i,s}, u_{i,t}) = \begin{cases} (NL_i^1 + P_{i,t} \cdot MC_{i,1}) \cdot u_{i,t} \\ (NL_i^2 + P_{i,t} \cdot MC_{i,2}) \cdot u_{i,t} \\ (NL_i^3 + P_{i,t} \cdot MC_{i,3}) \cdot u_{i,t} \end{cases} \quad (3-5)$$

where

$u_{i,t}$ status of unit i at hour t (1 when committed and 0 otherwise)

C_i^E cost of output power from committed unit i [\$/h].

3.2.2 Modelling of Interruptible Loads

The disconnection of loads is performed manually or automatically depending on the scheme or class of reserve the customers have chosen. The latter form is used in the problem modelled in this thesis. The load connected to the electric power network is via a under-frequency relay (UFR) when the scheme requires the disconnection of load to be performed automatically. The UFR is activated and opens up the connection of the load from the network which reduces the burden on generation. The amount of the interruptible loads (ILs) to participate in the electricity market must meet a minimum MW value and this depends on market requirement. Some system operators allow the aggregation of small loads to meet the participation requirement as illustrated in Fig. 3-4.

Figure 3-4 Configurations of ILs participating in electricity market

These aggregated loads may spread over an area from different households or small industries represented in Fig. 3-4(a). For an industry with a large number of small loads, the aggregation can also be formed within the industry as in Fig. 3-4(b).

The activation of the UFRs will cause the ILs that opt for the specific reserve class to disconnect from the network instantly when their services are called for during

contingency. The price offer from Demand Side Agents (DSAs) for ILs participating in the electricity market is therefore in dollars per MW hour of the IL block delineated in Fig. 3-5.

Figure 3-5 Reserve Bidding Prices of Demand Side Agents

This thesis has considered three large loads in the model when all these loads choose to participate under the same classes of a reserve market and to activate at the same frequency. The offering price and the MW block are then the imperative numbers needed to get the reserve share. The products of the offering price and block MW for the DSA should satisfy (3-6) as follows:

$$B_1^{ils} IL_1^{offer} < B_2^{ils} IL_2^{offer} < B_3^{ils} IL_3^{offer} \quad (3-6)$$

where

$$B_1^{ils} / B_2^{ils} / B_3^{ils} \quad \text{reserve price offered from DSA 1, 2 and 3 [$/MWh]}$$

$$IL_1^{offer} / IL_2^{offer} / IL_3^{offer} \quad \text{reserve offered by DSA 1, 2 and 3 [MW].}$$

The lowest price for the block offer from DSA normally gets the reserve offer first. But this will depend on the size of the block, reserve offer from other providers and the overall cost optimisation process. Based on equation (3-6) and Fig. 3-5, when an initial amount of reserve is allocated to DSA, the exact MW available from DSAs is determined by setting their status

$$\begin{aligned}
 0 \leq R_t^{ils} \leq IL_1^{offer} & \Rightarrow u_{1,t}^{ils} = 1 ; u_{2,t}^{ils} = u_{3,t}^{ils} = 0 \\
 IL_1^{offer} < R_t^{ils} \leq \sum_{i=1}^2 IL_i^{offer} & \Rightarrow u_{1,t}^{ils} = u_{2,t}^{ils} = 1 ; u_{3,t}^{ils} = 0 \\
 IL_2^{offer} < R_t^{ils} \leq \sum_{i=1}^3 IL_i^{offer} & \Rightarrow u_{1,t}^{ils} = u_{2,t}^{ils} = u_{3,t}^{ils} = 1
 \end{aligned} \tag{3-7}$$

where

i	DSA number
t	time in hour when DSA i has been allocated with reserve [h]
R_t^{ils}	initial overall reserve allocated to DSAs at hour t [MW]
$u_{i,t}^{ils}$	status of DSA i at hour t (1 indicates allocated with reserve and 0 otherwise).

The arrangement in (3-7) may change depending on the determination of system optimal cost. The total MW of reserve committed based on the initial reserve value and the DSA blocks of MW available from equation (3-7) is

$$R_t^{ils} = \sum_{i=1}^{NIL} IL_i^{offer} \cdot u_i^{ils} \tag{3-8}$$

and the cost for each DSA is formulated as

$$C_i^{ils}(R_{i,t}^{ils}, B_i^{ils}, u_{i,t}^{ils}) = R_{i,t}^{ils} \cdot B_i^{ils} \cdot u_{i,t}^{ils} \tag{3-9}$$

subjected to

$$R_{i,t}^{ils} = IL_i^{offer} \tag{3-10}$$

where

NIL	total number of DSA number
C_i^{ils}	cost of reserve from DSA i [\$/h]

$R_{i,t}^{ils}$ reserve offer from DSA i at hour t [MW].

3.3 Modelling of Expected Energy Not Served

Traditionally, determination of the expected energy not served (EENS) is performed by setting up a capacity outage probability table (COPT) based on a load duration curve [29]. The EENS is an energy deficiency amount while the COPT is based on a capacity generation model used for the energy deficiency approach. The product of the probability and energy curtailed from each state of COPT is an EENS value for that specific capacity amount of the available to meet system demand. The summation of all the EENS values from each state of the array gives the final value on the expected unserved. The value will change when additional units are added or removed. Based on the above description, EENS can be calculated [29] using the following equation

$$EENS = \sum_{k=1}^w p_k E_k \quad (3-11)$$

where

w all possible states for different unit capacity
 p_k probability state k for the available capacity calculated using COPT
 E_k Energy calculated in state k [MWh].

This EENS concept was originally formulated for long term power system planning. In this work, the EENS is used to determine the operating reserve requirement (ORR) level for a study period of 24 hours. It is explicitly determined in the study. The scheduled units are assumed to operate at the beginning of each hour while the demand is constant for the lead time of the marginal unit. EENS in each hour is calculated independently.

The reliability of unit l , an approximated probability value formulated based on equation (2-1), is given by

$$A_l = 1 - P(\text{unit fail during lead time}) = e^{\frac{-\tau}{MTTF}} \quad (3-12)$$

where

l	index for unit
τ	lead time variable [h]
$MTTF$	mean time to failure [h].

Based on equation (3-11), the loss of load probability ($LP_{i,t}$) and loss of load amount ($LC_{i,t}$) due to outage of online unit i at hour t in a system of thermal units are

$$LP_{i,t} = \prod_{l=1}^U A_l \cdot \prod_i (1 - A_i) \quad (3-13)$$

$$LC_{i,t} = Load_t - \sum_{l=1; l \neq i}^U (P_{l,t} + R_{l,t}) \quad (3-14)$$

where

U	total number of online units
$Load_t$	system demand at hour t [MW]
$P_{i,t}$	MW generation from online unit l at hour t [MW]
$R_{i,t}$	MW reserve from the online unit l at hour t [MW].

A set of binary variables, $\theta_{i,t}$, $i = 1, 2 \dots U$ is implemented to model loss of load caused by outages. The variable $\theta_{i,t}$ is equal to 1 when the system demand is greater than all of the available energy scheduled and reserves procured. It is equal to 0 when the system demand is smaller or equal to all of the available energy and reserves procured.

$$\frac{LC_{i,t}}{TCR} \leq \theta_{i,t} \leq 1 + \frac{LC_{i,t}}{TCR} \quad (3-15)$$

where the sum of total capacity of the generating units is

$$TCR = \sum_{j=1}^U (P_{j,t} + R_{j,t}) \quad (3-16)$$

The outage of generation units may trigger interruption on the demand side. Hence, the availability of IL relies on the reliabilities of generating units significantly. This availability can be modelled as a function of the multiplication of the availability of the generating units supplying the demand and the product of a reliability factor comprising the reliability of the UFRs/CBs and the willingness of the IL owners to disconnect the load when needed.

The reliability computation of IL l is

$$\begin{aligned} A_{l,t}^{IL} = & \prod_{a=1}^{NES} \prod_{i_a=1}^{Ua} A_{i_a} + \sum_{a=1}^{NES} \left[\sum_{i_x=1}^{Ua} \left\{ (1 - A_{i_x}) \cdot \prod_{\substack{i_a=1 \\ i_a \neq i_x}}^{Ua} A_{i_a} \prod_{\substack{b=1 \\ b \neq a}}^{NES} \prod_{i_b=1}^{Ub} A_{i_b} \right\} \right] \\ & + \sum_{a=1}^{NES} \left[\sum_{i_x=1}^{Ua} \sum_{i_y > i_x}^{Ua} \left\{ (1 - A_{i_x}) \cdot (1 - A_{i_y}) \cdot \prod_{\substack{i_a=1 \\ i_a \neq \{i_x, i_y\}}}^{Ua} A_{i_a} \prod_{\substack{b=1 \\ b \neq a}}^{NES} \prod_{i_b=1}^{Ub} A_{i_b} \right\} \right] \\ & + \sum_{a=1}^{NES} \left[\sum_{i_x=1}^{Ua} \sum_{i_y > i_x}^{Ua} \sum_{i_z > i_y}^{Ua} \left\{ (1 - A_{i_x}) \cdot (1 - A_{i_y}) \cdot (1 - A_{i_z}) \cdot \prod_{\substack{i_a=1 \\ i_a \neq \{i_x, i_y, i_z\}}}^{Ua} A_{i_a} \prod_{\substack{b=1 \\ b \neq a}}^{NES} \prod_{i_b=1}^{Ub} A_{i_b} \right\} \right], \\ & Ua, Ub \in \{U1, U2, U3, \dots, Un\}, \quad i_a, i_b, \in \{i_1, i_2, i_3, \dots, i_n\} \end{aligned} \quad (3-17)$$

where

NES	the number of unit combination elements in a set
a, b	the indices of the unit combination elements
$U1$	the number of units scheduled at hour t

$U2$	the number of combinations of two units scheduled at hour t
$U3$	the number of combinations of three units scheduled at hour t
Un	the number of combinations of n units scheduled at hour t
$i, i_x, i_y, i_z, i_1, i_2, i_3 \dots i_n$	the indices of the units
j, k	the indices of the units

subject to the followings:

For U1,

$$P_{i_1}^{min} \geq R_{l,t}^{ils} \quad (3-17a)$$

For U2,

$$P_{i_2}^{min} = P_i^{min} + P_j^{min} \geq R_{l,t}^{ils} \quad (3-17b)$$

$$\{P_i^{min}, P_j^{min}\} < R_{l,t}^{ils} \quad (3-17c)$$

$$A_{i_2} = A_i \cdot A_j$$

For U3,

$$P_{i_3}^{min} = P_i^{min} + P_j^{min} + P_k^{min} \geq R_{l,t}^{ils} \quad (3-17d)$$

$$\{P_i^{min}, P_j^{min}, P_k^{min}\} < R_{l,t}^{ils} \quad (3-17e)$$

$$A_{i_3} = A_i \cdot A_j \cdot A_k \quad (3-17f)$$

For Un,

$$P_{i_n}^{min} = P_i^{min} + P_j^{min} + P_k^{min} + \dots + P_n^{min} \geq R_{l,t}^{ils} \quad (3-17g)$$

$$\{P_i^{min}, P_j^{min}, P_k^{min}, \dots, P_n^{min}\} < R_{l,t}^{ils} \quad (3-17h)$$

$$A_{i_n} = A_i \cdot A_j \cdot A_k \cdot \dots \cdot A_n \quad (3-17i)$$

Unit outages of up to the third order are considered.

Equation (3-17) is a function of lead time of units because its energy is drawn from generating units, as illustrated in (3-12). The final availability of IL l at hour t is then formulated with the reliability factor (π_1), which is independent of lead time and can be obtained from past records of load operation as follows

$$A_{l,t} = \pi_l \cdot A_{l,t}^{IL} \quad (3-18)$$

The expression shows that the reliability of ILs depends on the reliability of the generating units that supply the power and the reliability for IL to disconnect from the grid when requested. A poor reliability factor will degrade the availability of the IL.

When DSAs offer ILs in the electricity market, the reliability for the number of DSAs in $(\prod_{l=1}^{NIL} A_{l,t})$ is multiplied and incorporated in equation (3-13). An additional

term on reserve contributed by DSAs, $(\sum_{l=1}^{NIL} R_{l,t}^{ils})$, is added in equations (3-14) and (3-

16). NIL is the number of DSAs participated in the electricity market.

3.3.1 EENS Caused by Outages of Online Units

The expected energy not served functions under single contingency occurrences caused by online unit outages are given by

$$EENS_{i,t}^S = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t} \quad (3-19a)$$

$$EENS_{i,j,t}^S = \theta_{i,j,t} \cdot LP_{i,j,t} \cdot LC_{i,j,t} \quad (3-19b)$$

$$EENS_{i,j,k,t}^S = \theta_{i,j,k,t} \cdot LP_{i,j,k,t} \cdot LC_{i,j,k,t} \quad (3-19c)$$

Equations (3-19a) to (3-19c) are the EENS formulation from first to third order outages of the online units. This work has considered up to third order outages.

The summation of equations (3-19a) to (3-19c) is the EENS due to the outage of online units at period t ,

$$EENS_t^S = \sum_{i=1}^U EENS_{i,t}^S + \sum_{i=1}^U \sum_{j>i}^U EENS_{i,j,t}^S + \sum_{i=1}^U \sum_{j>i}^U \sum_{k>j}^U EENS_{i,j,k,t}^S \quad (3-20)$$

where

i, j, k indices for energy and reserve providers, e.g. generating units.

3.3.2 EENS Caused by Interruptible Loads

The malfunction or failures of the UFR or SCADA may result in ILs not responding when required. The EENS caused by ILs must have an outage of at least an online unit followed by the IL's failure to respond. The formulation of EENS contribution from ILs at period t is

$$EENS_t^{IL} = \sum_{k=1}^{NIL} \sum_{i=1}^U EENS_{k,i,t}^{IL} + \sum_{k=1}^{NIL} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^{IL} + \sum_{j=1}^{NIL} \sum_{k>j}^{NIL} \sum_{i=1}^U EENS_{j,k,i,t}^{IL} \quad (3-21)$$

The summation terms on the right of equation (3-21) are the EENS for the second order to third order outages. The first term on the right is second order outages. An online unit i had to fail before ILs are called in for their service. In this case IL k also failed to provide the service. The next two terms are third order outages with two unit i and j failing followed by the failure of IL k , and one unit i failing followed by failures of ILs j and k .

3.3.3 Pictorial Representation of EENS

The EENS terms formulated can be pictorially represented using a plot of loss of load depicted in Fig. 3-6. The EENS expression (3-20) is represented by the area ABCDEFA when there is no reserve allocated to DSAs for ILs. For the system incorporated with ILs and allocated with reserve, the EENS expression (3-20) is then represented by the area EBCDE. If there is no IL failure, the area ABEFA will be the energy recovery from ILs. Nonetheless, the failure of ILs as formulated in (3-21) is

represented by area FBEF. Hence the summation of (3-20) or area EBCDE due to the outage of online units and (3-21) or area FBEF is the total EENS for the system with ILs. This final expected energy not served at period t ($EENS_t$) is the summation of EENS due to the outage of online units during operation ($EENS_t^S$) and failures of ILs after they were initiated but failed to disconnect from the grid ($EENS_t^{IL}$), i.e.

$$EENS_t = EENS_t^S + EENS_t^{IL} \quad (3-22)$$

Figure 3-6 An area plot showing EENS contribution from system with online thermal units and ILs

3.4 Problem Formulation

In this section, the schedule cost is obtained through the UC optimisation function to ensure that all generation units from Gencos are scheduled in the most economical way while satisfying the system and unit constraints. Other than the energy and reserve bids from Gencos, the reserve offering bids from DSAs together with the cost of EENS are also incorporated into the objective function. A combined schedule cost of energy and reserve and EENS cost has to be at its minimum.

3.4.1 Objective Function

The objective function of the UC problem is to minimise the schedule cost of energy and reserve, and the EENS cost of outages,

$$\begin{aligned} \text{Min} \left\{ \sum_{t=1}^T \sum_{i=1}^U \left[C_i^E(P_{i,t}, MC_{i,s}, u_{i,t}) + cr_i^{SU} \cdot u_{i,t} (1 - u_{i,t-1}) + C_i^{SR} (cr_i^{SR} \cdot R_{i,t} \cdot u_{i,t}) \right] \right. \\ \left. + \sum_{t=1}^T EENS_t \cdot VOLL \right\} \end{aligned} \quad (3-23)$$

where

T	total number of hours in the time period
U	total number of generation units
C_i^{SR}	cost of spinning reserve from committed unit i [\$/h]
cr_i^{SR}	reserve bidding price from unit i scheduled online [\$/MWh]
$VOLL$	value of lost load [\$/kWh].

From the optimisation function, the first and third terms denote the energy and spinning reserve costs from unit i scheduled online. The second term is the start up cost incurred when the unit is scheduled to commit for that hour. This cost will only be incurred in the first hour the unit is initiated to operate and will remain zero for the rest of the operating hours. The fourth term is the EENS cost. It is a product of EENS value with VOLL at hour t . Because of the complexity in formulating an equitable VOLL, it is usually obtained from surveys [82, 83]. VOLL varies from one system to another depending on the value that consumers placed on un-served energy. This thesis has considered VOLL as a fixed value in the study.

When ILs are incorporated into the system, the objective function is reformulated as

$$\begin{aligned}
Min \left\{ \sum_{t=1}^T \sum_{i=1}^U \left[C_i^E(P_{i,t}, MC_{i,s}, u_{i,t}) + cr_i^{SU} \cdot u_{i,t} (1 - u_{i,t-1}) + C_i^{SR}(cr_i^{SR} \cdot R_{i,t} \cdot u_{i,t}) \right] \right. \\
\left. + \sum_{t=1}^T \sum_{i=1}^{NIL} C_i^{ils}(R_{i,t}^{ils}, B_i^{ils}, u_{i,t}^{ils}) + \sum_{t=1}^T EENS_t \cdot VOLL \right\} \quad (3-24)
\end{aligned}$$

3.4.2 Constraints

In this thesis, a number of constraints has to be incorporated in the UC modelling process. These constraints are system and unit constraints.

(a) System constraints

$$\sum_{i=1}^U P_{i,t} \cdot u_{i,t} = Load_t \quad t = \{1 \dots T\} \quad (3-25)$$

$$\sum_{i=1}^U R_{i,t} \cdot u_{i,t} + \sum_{i=1}^{NIL} R_{i,t}^{ils} = ORR_t \quad t = \{1 \dots T\} \quad (3-26)$$

where

ORR_t 10-minute operating reserve requirement at hour t [MW].

subjected to thermal unit constraints:

(b) Reserve contribution constraint

$$R_{i,t} = \min \left\{ P_i^{max} - P_{i,t}, RUR_i \cdot \frac{10}{60} \right\} \quad t = \{1 \dots T\} \quad (3-27)$$

where

P_i^{max} generating unit i maximum available capacity [MW]

RUR_i ramp up rate of unit i [MW/h].

(c) Generating capacity constraints

$$P_i^{min} \leq P_{i,t} \cdot u_{i,t} \leq P_i^{max} \quad t = \{1 \dots T\} \quad (3-28)$$

$$0 \leq R_{i,t} \cdot u_{i,t} \leq P_i^{max} - P_{i,t} \cdot u_{i,t} \quad t = \{1 \dots T\} \quad (3-29)$$

where

P_i^{min} generating unit i minimum available capacity [MW].

(d) Ramping constraints

$$P_{i,t} - P_{i,t-1} \leq RUR_i \quad t = \{1 \dots T\} \quad (3-30)$$

$$P_{i,t-1} - P_{i,t} \leq RDR_i \quad t = \{1 \dots T\} \quad (3-31)$$

where

RDR_i ramp down rate of unit i [MW/h].

Thermal units require a period of time to undergo temperature change. This transition time may take more than one hour to bring a unit online or shutdown fully. Violation to these restrictions will damage the material structure of the unit, leading to a reduction in unit's operation efficiency and life span. The thermal unit operation restrictions that have to be followed are:

(e) Minimum up/down time constraints

$$(X_{i,t}^{on} - T_i^{on}) \cdot (u_{i,t-1} - u_{i,t}) \geq 0 \quad t = \{1 \dots T\} \quad (3-32)$$

$$(X_{i,t}^{off} - T_i^{off}) \cdot (u_{i,t} - u_{i,t-1}) \geq 0 \quad t = \{1 \dots T\} \quad (3-33)$$

where

$X_{i,t}^{on/off}$ time duration for on/off state of unit i at hour t [h]

$T_i^{on/off}$ maximum on/off time of unit i [h].

Therefore, the unit should not be turned off immediately once it is spinning and should not be recommitted before the minimum down time period lapses.

3.4.3 Determination of Operating Reserve Requirement

The 10-minute ORR is a composition of reserves from online generators and ILs. A 10-minute ORR scheduling which integrates the probabilistic approach into the UC

problem via an initial deterministic reserve criterion is presented. The algorithm of the proposed probabilistic method is delineated in Fig. 3-7. This method is different from the risk index setting technique such as pre-specified a unit commitment risk (UCR) or a marginal/healthy state as a conversance criterion. This risk index setting technique lacks intuitive quantifiable interpretation on the criterion set and thus does not tell the reserve amount that should be scheduled or the expected un-served energy based on the units scheduled to meet the system demand. The criterion setting for this proposed method is an acceptable hourly average un-served energy, i.e. $EENS_{\max}$ (MWh), which terminates the reserve procurement iteration when the scheduled system reliability meets this criterion. The reserve procurement is separately considered for each scheduling interval. From the flow-chart in Fig. 3-7, the termination in each interval of the UC problem iteration is decided by the following constraints

$$EENS - EENS_{\max} < 0 \quad (3-34)$$

and

$$|EENS - EENS_{\max}| \leq \varepsilon \quad (3-35)$$

where

ε a diminutive value which can be preset by the system operator.
This study has ε set to 2% of $EENS_{\max}$.

Figure 3-7 A probabilistic approach with an initial deterministic reserve criterion

3.4.4 Penalty Cost Calculation Imposed on Grid Service Providers (GSPs) and ILs

During contingencies, the selected reserve providers are to provide the necessary power to alleviate the amount of lost load. Failure to do so may negatively affect the incidence of lost load. Providers who fail to supply the reserve will be penalised. This section presents a formulation of the penalty cost to be imposed on the GSP or IL if the related UFR/CB fails to operate when its service is needed to disconnect the load from the grid. The GSP who is responsible for the routine maintenance of UFRs/CBs is penalised if ILs fail to disconnect due to poor maintenance. Similarly, ILs who are responsible for the maintenance of their UFRs/CBs are penalised if they too fail to respond either automatically or manually when a manual disconnection is required.

There is still a possibility that an IL may malfunction. $ERIL_t$, an EENS in kilowatt hours, is computed based on the reserve allocated to ILs that fail to disconnect at hour t . It is formulated as

$$ERIL_t = \frac{\sum_{i \in comIL} R_{i,t}^{ils}}{\sum_{i=1}^{NIL} R_{i,t}^{ils}} \cdot EENS_t^{IL} \quad (3-36)$$

where $comIL$ is a set of all ILs that fail to disconnect from the grid when their services are required. Two proportional share factors are formulated to calculate the share responsibilities of the total penalty cost among the ILs that fail to disconnect so that their energy usage is released for use by others during an emergency. The first factor, $GUPSF_{i,t}$, is used to calculate the share ratio when the UFRs/CBs connected to ILs are maintained by the GSP and the failure to disconnect is not caused by the behaviour of the IL owners

$$GUPSF_{i,t} = \frac{R_{i,t}^{ils} \cdot (\pi_i)^{-1} \cdot (1 - u_{i,t}^{ils})}{\sum_{l \in comIL} R_{l,t}^{ils} \cdot (\pi_l)^{-1} \cdot (1 - u_{l,t}^{ils})} \quad (3-37)$$

Thus, the GSP should be responsible if there is a failure. The second factor, $IUPSF_{i,t}$, is calculated when the UFRs/CBs are maintained by ILs and the failure to disconnect is caused by the behaviour of ILs

$$IUPSF_{i,t} = \frac{R_{i,t}^{ils} \cdot B_i^{ils} \cdot (\pi_i)^{-1} \cdot (1 - u_{i,t}^{ils})}{\sum_{l \in comIL} R_{l,t}^{ils} \cdot B_l^{ils} \cdot (\pi_l)^{-1} \cdot (1 - u_{l,t}^{ils})} \quad (3-38)$$

where $comIL$ is a set of only the ILs that failed to disconnect, and the UFRs/CBs are maintained by ILs. A system total penalty cost ($STPC_t$) at hour t can be computed as a product of the actual outage megawatts ($AOMW_t$) at hour t and VOLL. It is formulated as

$$STPC_t \text{ ($) } = AOMW_t \cdot VOLL \quad (3-39)$$

The penalty cost for the grid service provider ($PCGSP_{i,t}$) who is responsible for the maintenance of the UFRs/CBs that fail to operate at hour t is

$$PCGSP_{i,t} \text{ ($) } = \frac{ERIL_t}{EENS_t^S + ERIL_t} \cdot GUPSF_{i,t} \cdot STPC_t \quad (3-40)$$

When the IL providers are responsible for the maintenance of UFRs/CBs and they fail to operate either automatically or manually, the penalty cost for the i^{th} IL ($PCIL_{i,t}$) that fails to disconnect when required at hour t is

$$PCIL_{i,t} \text{ ($) } = \left(\frac{ERIL_t}{EENS_t^S + ERIL_t} \cdot STPC_t - \sum_{j=1}^{GSL} PCGSP_{j,t} \right) \cdot IUPSF_{i,t} \quad (3-41)$$

where $GSIL$ is the total number of ILs that fail to disconnect and the GSP is responsible for the maintenance of these UFRs/CBs.

3.5 UC Simulation Results

The presented methodology is first tested on a small system which comprises 6-thermal unit with and without DSA participation. The 6-thermal unit system is listed in Appendix Table A-1 and the simulation results are presented in [174]. This small system is then replaced by a 26-thermal unit system. The data is shown in Table A-2. The data of these units is extracted from the 32-unit IEEE reliability test system [175]

Gencos will submit a 3-segment energy offer curve to bid for the energy and 1-segment reserve offer curve for reserve bidding. The energy offer prices of thermal units are also presented in Table A-2. As discussed in the earlier section that a thermal unit in this research refers to coal-fired steam generator. The unit needs more than an hour to start up before it can be synchronised and connected to the network. Thermal units can only provide reserve while online and spinning. The spinning reserve offer prices of the thermal units are set to 10% of their maximum energy offer prices. Gencos also need to submit unit's MTTF which is needed to justify the allocation of energy and reserve to the unit for system reliability, and for EENS cost calculation purposes.

DSAs incorporated in this work are to offer reserve in the form of interruptible loads (ILs) which compete directly with the Gencos. The IL data is shown in Table A-3, which consists of reserve bidding price for each MW block quantity and MTTF value. The reserve offer prices for ILs are in dollar per megawatt hour for each block.

The system demand curve level is depicted in Table A-6. It has shown that the peak load period is between hour 8 and hour 22 where the demand levels are above 2400

MW. The off-peak hours covers the late night and early morning periods. The UC problem is modelled as 1-hour time interval.

3.5.1 Simulation on 26-Thermal Unit System

In this subsection, a short study on quantifying the reserve level is first performed. This is followed by a system comprising 26-thermal unit modelled as a base case system. For comparison purposes, this base case system without DSAs serves as a basis to illustrate how DSA affects the power market solution.

A. Quantifying Reserve Level

The assessment criterion for the proposed probabilistic approach method to procure the 10-minute OR should be determined through a cost/benefit analysis approach. Otherwise, it may result in procuring either excessive reserve or too little reserve. The former is a waste of resources and the latter leads to a large un-served load during severe contingencies. The system VOLL, an estimated expected cost of interruption to consumers, also plays an important role as it effects the EENS cost in the procurement of reserve commodity. The calculation and determination of VOLL are complex and tedious [36].

The cost/benefit analysis (CBA) would be able to set the assessment criterion, i.e. the reliability level at an optimal point when the marginal cost of providing more reserve is equal to the marginal value of the reserve to alleviate loss of load.

The relation of the schedule cost, the EENS cost and the total cost is elucidated in Fig. 3-8.

Figure 3-8 A typical plot on cost/benefit analysis

The CBA enables the system operators to procure the right amount of reserve. Through CBA, the cost of procuring the reserve can be made optimal. This is important as the cost of running the system is generally passed on to the consumers.

B. Base Case Studies

The base case is modelled which comprises only 26-thermal units in the system. The objective function is formulated without the demand side participation. The optimal cost is obtained using the CBA approach as depicted in Fig. 3-9. The VOLL is set to 4 \$/kWh. The optimal cost for the 24-hour study period is \$778,237 which is obtained at a reliability level of 0.57 as indicated with a circle (O). The total reserve quantity procured in the 24-hour study period is 4,203 MW.

Figure 3-9 Base case system total cost determination via cost/benefit analysis with $VOLL = 4 \text{ \$}/\text{kWh}$

C. Computation Performance and Stability Studies

As discussed in the earlier chapter, the pre- and post-processing modules of UC are programmed in MATLAB and the UC is coded using GAMS. The UC is solved by CPLEX in GAMS.

MATLAB is primarily used for numerical computing. It is mainly used by researchers in academic and research institutions, rather than used in industries. MATLAB is an interpreted language. The executing time is slow compared to that of the commercial software. GAMS is a commercial software and is able to solve a complex and large model. CPLEX is an optimiser designed to solve a complicated and large problem. It is used to solve linear programming, integer programming, quadratically constrained and mixed integer programming problems [172]. With CPLEX, complex problems can be solved quicker and more effectively.

The required computation of the proposed methodology depends on the MIP duality gap, system size, generation types and the convergence tolerance, i.e. EENSmax. In order to reduce the computation time, the MIP duality gap and convergence tolerance

can be relaxed. The default duality gap in GAMS is zero. In this work, the duality gap is set to 0.1% and the convergence tolerance (EENSmax) is set to 2%. Table 3-1 shows the computation time of the various methodologies used to solve UC for a 26-unit system.

Table 3-1 Comparison of CPU time among the various methodologies used to solve UC

Methods	CPU Time (Sec)
Simulated Annealing (SA)	1810
Evolutionary Programming (EP)	1785
Dynamic Programming (DP)	1860
Largrangian Relaxation (LR)	1878
Mix Integer Programming (MIP)	239.2

Other than MIP, all the above methodologies are modelled using the MATLAB software package. For MIP, the UC is solved via GAMS/CPLEX. Hence, the computation time is faster compared to that of others. However, CPLEX uses a branch and cut algorithm to solve linear programming and sub-problems for problems with integer variables. There will be many sub-problems generated by a single mixed integer problem. Hence it is computation intensive and a substantial storage resource is required. The proposed optimisation problem can easily run out of memory if the solution is not found shortly. The program will terminate with an unrecoverable integer failure message or will terminate with one or more arguments not assigned, or abnormal GAMS termination resulted. Hence its solution process needs to be designed properly.

3.5.2 Simulation of Thermal Unit System with Demand Side Participation

Three demand side agents, each representing its customer from a heavy industry, are incorporated into the existing 26-thermal unit system. These DSAs carry two huge 20 MW blocks and one 15 MW block of loads. When reserve is allocated to them and if

their services are called for, the ILs will disconnect from the grid automatically in a full MW block quantity.

A constraint which allows at least 50% of ORR to be spinning is set.

$$\sum_{i=1}^{NIL} R_{i,t}^{ils} \cdot u_{i,t}^{ils} \leq ORR_t \cdot 0.5 \quad (3-42)$$

The following sub-section will study the reliability factors of ILs and the subsequent sub-sections assume that the reliability factor (π) of ILs is hypothetically assumed to be 0.997.

A. *Reliability Factors of ILs*

The simulation results on the variation reliability factors (π_i) of ILs are tabulated in Table 3-2. With a unity reliability factor, the availability of an IL will depend solely on the availability of generating units. When the reliability factor of ILs is less than unity, both the total amount of reserve procured and the total cost for the 24-hour period increase.

Table 3-2 Total reserve quantity and various costs at 24-hour study period with normalised EENS set to 0.52

	IL Reliability Factor					
	1	0.995	0.990	0.980	0.970	0.950
Total Reserve (MW)	4628	4635	4644	4653	4673	4697
Reserve Cost (\$)	8,647	8,657	8,668	8,678	8,761	8,788
EENS of ILs (kWh)	4.11	205.78	406.56	801.73	1,185.11	1,926.19
Total Energy Cost (\$)	715,999	716,074	716,149	716,220	716,939	717,162
Total Cost (\$)	765,806	765,876	765,924	766,061	766,678	766,916

B. *Demand Side Participation*

Fig. 3-10 shows the total cost curve for the system with and without DSA participation for the 24-hour study period. VOLL is set to 4 \$/kWh. The incorporation of DSAs has shown significant cost reduction. Each point of the total cost curve for the system with ILs is below the total cost of the base case. From the

plot, the reliability of the systems with incorporation of ILs has improved at a lower optimal cost. However, a higher amount of total reserve for the 24-hour period has to be procured as manifested in Table 3-3. Even though a certain amount of reserve has already been allocated to DSAs, additional reserve may have to be scheduled from conventional thermal units in order to reduce the EENS to meet the criterion. This elucidates why a higher reserve amount has been procured for system incorporated with DSAs. Although a higher reserve is procured, the schedule cost is lower than that of the base case. The allocation of reserve for ILs is able to reduce the number of online expensive conventional thermal units. This cost reduction is mainly contributed by the lower energy cost when expensive thermal units are scheduled less.

Figure 3-10 Total costs plot on base case system and system with ILs at VOLL = 4 \$/kWh

Tables 3-4 and 3-5 present the UC schedule status for the base case and system incorporated with DSAs at optimal cost, respectively. With DSAs, units 12 and 13 are de-committed during hours 1 to 5. Units 3 and 4 at hour 7, and unit 23 from hour 18 to hour 22 have also been de-committed. These de-committed units are the

marginal units for these specific hours. If they are not de-committed, they will incur a higher energy cost as shown in the base case.

Table 3-3 Optimal total cost obtained at VOLL = 4 \$/kWh for 24-hour study period

	Unreliability Level	Reserve (MW)	Schedule Cost (\$)	EENS Cost (\$)	Total Cost (\$)
Base Case System	0.57	4203	723,642	54,595	778,237
System with ILs	0.52	4628	715,999	47,807	765,806

Table 3-4 UC schedule for Base Case system

Unit	Period																								
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
2	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
3	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
4	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
16	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
22	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
23	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 3-5 UC scheduled for 26-thermal unit system with ILs

Unit	Period																								
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
2	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
4	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
16	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
22	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
23	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0
24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Demand Side Agents Status																									
1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

C. Variation on MW Blocks of ILs

This sub-section studies how the MW block size of ILs affect the power system reliability and total cost. The study is performed by setting up additional three cases in the simulation. These three cases raise the MW block of ILs by a factor of 1.4, 1.8 and 2.2. The total cost curves of these cases are shown in Fig. 3-11. A larger block size of ILs is able to reduce the total cost and the unreliability level index and makes the system more reliable. The dotted ellipse indicates that the reserve allocated to DSAs with large a MW block is restricted to 50% of the ORR setting. At these lower reliability levels, less reserve is procured and the total reserve from DSAs tends to hit the restriction faster.

Figure 3-11 Total cost curves on variation of the size of ILs MW blocks with VOLL = 4 \$/kWh

Fig. 3-12 shows a bar-chart on the EENS contributions from energy and reserve providers when the MW block size of ILs varies. It can be seen that the EENS of ILs is iota as compared to that of conventional thermal units, even when the block size of ILs has increased. This is because ILs are relatively reliable owing to higher MTTF value and they will contribute to EENS only when there is an outage of an online unit.

Figure 3-12 A bar-chart showing EENS contributed by online units and ILs

D. Variation of DSAs Reserve Bidding Prices

This sub-section studies on how the bidding price offered from ILs will affect the system overall total cost and reliability. Other than the base case, five systems incorporated with ILs have been modelled. The reserve bidding prices offer from these ILs are multiplied by a factor of 1 (original price), 2, 4, 8 and 50. The last factor is a heuristic study on how the reserve will be allocated when the reserve provider has its bidding price raised to a sky-high value. The results of these bidding prices are shown in Fig. 3-13.

With an increase in bidding price from DSAs, less reserve is allocated to ILs. Those marginal units of Gencos become competitive enough to win back their reserve shares. From the plot, the increase in bidding prices has raised the system total cost and the reliability level at optimal cost has deteriorated. With high reserve bidding prices from DSAs, the DSAs will become uncompetitive in the electricity market.

Figure 3-13 Total cost curves on variation of reserve bidding prices from DSAs with VOLL = 4 \$/kWh

As less reserve has been allocated to DSAs, there is a reduction in EENS contribution from ILs as shown in Fig. 3-14. The EENS contribution from online units has increased considerably and this leads to an increase in the overall EENS.

Figure 3-14 A bar-chart showing EENS values with variation of reserve bidding prices from ILs variation

3.5.3 Systems Incorporated with DSAs as VOLL Varies

This section studies the system with DSAs participated in the electricity market for reserve contribution as VOLL varies.

The system total costs with VOLL variation are plotted as shown in Fig. 3-15. The increase on the VOLL causes the overall total costs to increase. At high unreliability, less reserve amount is carried by the system. At low unreliability, more expensive reserve is procured which leads to an increase in reserve cost. This results in a higher total cost since more conventional thermal units are needed to commit online even though DSAs participate in the electricity market. The increase in VOLL has caused the system reliability at optimal cost drifted towards the left side of abscissa. This means that the system is more reliable at a higher VOLL.

Figure 3-15 Total system cost curves with DSA participation and variation of VOLL

The unreliability level indices are plotted against the VOLL variation as shown in Fig. 3-16. The figure shows two curves: the unreliability level curves for the base case and the system with ILs. A lower unreliability level is obtained for the system incorporated with ILs than that of the base case. This unreliability level becomes smaller when VOLL increases since more reserve is procured by the system. The

difference between the two system unreliability levels become a constant when VOLL is at 5 \$/kWh and above. This is mainly due to the presence of the MW block offer from DSAs. The reliability levels remain constant for both systems as they have reached the limit that additional expensive reserve procured is less economical than the VOLL payment.

Figure 3-16 A plot on unreliability level against VOLL variation at optimal cost

3.5.4 Penalty Cost

The simulation results from Section 3.5.3 with the original price and MW block size are used to calculate the penalty cost. The GSP or ILs will be responsible for the penalty cost if the UFRs/CBs fail to operate and ILs fail to provide the reserve service either automatically or manually. Table 3.6 depicts the penalty imposed on them if their service cannot be realised during operation. This calculation is illustrated by assuming that ILs failed to disconnect from the system grid, and an actual load MW is recorded according to these scenarios.

For the UFRs/CBs maintained by ILs or to be activated manually in scenario 1 in Table 3-6, the penalty cost calculation for a single IL that failed to disconnect depends on the ratio of the reserve offer from this IL to the total amount of reserve from ILs of the same category. For scenario 2, the penalty cost for an IL failure is the same as that for scenario 1 except that the UFRs/CBs of the failed IL are maintained

by the GSP. However, the results on the higher order IL failures are different than those presented earlier. The GSP will be penalised based on the offer MW amount and reliability factor of IL and not on the offer price because GSP does not participate in the price making decision but only knows the amount of load to which the UFR/CB is connected. Thus, if both the UFRs/CBs are maintained by the GSP and failed, the GSP will be penalised more on the larger MW block than on the smaller block as well as on the block with a poorer reliability factor.

Table 3-6 Penalty cost at hour 24 when IL(s) failed to disconnect from system grid

Scenario 1: UFRs/CBs of faulty ILs are maintained by IL owners and either activated automatically or manually							
Faulty ILs	Reserve (MW)	Reliability Factor, π	Reserve Offer Bidding Price (\$/MWh)	ERIL ₂₄ (kWh)	EENS ₂₄ (kWh)	Penalty (\$) on GSP or ILs	
						2	3
2	20	0.997	2	1.49	188.77	7.21	-
3	15	0.997	3	1.12	188.40	-	5.30
2, 3	35			2.61	189.89	6.29	7.08
Scenario 2: UFRs/CBs connected to both faulty ILs are maintained by GSP							
2, 3	35			2.61	189.89	7.64	5.73

Accordingly, the penalty cost will increase when the actual outage MW is higher than the values shown in the simulation. Likewise, a high VOLL, poor reliability of UFRs/CBs, large MW block size of ILs and/or prolonged outage duration will increase the penalty cost. The proposed scheme will force GSPs and ILs to maintain the UFRs/CBs of ILs in the most reliable state to avoid paying the penalty cost.

3.6 Summary

The integration of ILs from DSAs has shown that the system total schedule cost can be reduced and a higher system reliability can be achieved. Fig. 3-17 summaries the various factors that will affect the system reliability and economics. Cost reduction with improved reliability can be obtained by increasing the MW block size of ILs. The MW block size may be constrained by the system regulation and the total costs restricted to lower values as represented by the lower boundary curvature line of the

shaded region in Fig. 3-17. Increment on the bidding price from DSAs causes less reserve allocated to ILs. The total costs increase with deterioration in system reliability. This total cost increment and reliability deterioration are constrained by the upper boundary curvature line of the shaded region. This boundary line is the total cost curve for system with only thermal units, i.e. base case system.

Figure 3-17 Effect on system reliability and total cost for system which incorporates DSAs

Penalties imposed on the ILs and grid service providers will enforce routine maintenance performed on the relays and breaker of ILs which will improve the reliability of system operation and reduce the energy procurement cost.

Chapter 4

Electric Power System with Rapid-Start Units

4.1 Introduction

Gencos have employed gas turbines to operate a steam turbine which forms a combined cycle plant. Gas turbines in the combined cycle plant can also reconfigure and operate individually as open cycle gas turbines, OCGTs. The initiation and operation of OCGTs can be done by remote control. The issue on poor starting reliability or high failure rate of starting the OCGTs [120, 121] makes the units less wanted for energy production and reserve allocation. This is especially true on the latter as the energy is needed to mitigate losses during contingency. There is less alternative choice of resources within a short notice if the OCGTs failed when their services are called for.

In this chapter, a methodology that explicitly integrates the starting reliability of rapid-start generators into the EENS formulation of the UC problem is proposed. A technique on modelling the rapid-start unit considering the initiation time up to the 10 minutes of the OR requirement with pictorial representation of EENS contributions is presented. How each generator characteristic affect the system reliability and economics will be traversed. A penalty cost calculation on OCGTs which failed in starting up for NR contribution is proposed. The rapid-start units, OCGTs, will be studied in this chapter. The other rapid-start unit and a renewable source, hydro power generator, will be discussed in the next chapter.

4.2 Modelling of Open Cycle Gas Turbine Generators

In this section, the rapid-start generator, open cycle gas turbine (OCGT), will be studied. Comparing to hydro power generation unit, OCGT can be utilised to

generate electric power in any area as it is geographically independent. But it is subjected to a high starting failure rate as reviewed earlier. Equations formulated and derived in this chapter can also be applied to hydro power generation unit.

4.2.1 Evaluation of Starting Up Failures

The reliability of starting up the rapid-start unit successfully, is defined by IEEE (IEEE Std 762) [123], and is reproduced as

$$P_l^{SS} = \frac{SS_l}{SS_l + SF_l} \quad (4-1)$$

where

P_l^{SS}	Probability in starting up for unit l successfully
SS_l	Starting attempts succeeded in bringing unit l in service and connecting to the network within the specific timing
SF_l	Starting attempts failed to bring unit l in service within a specific timing.

The probability of failure on starting up the unit (P_l^{SF}) is

$$P_l^{SF} = 1 - P_l^{SS} \quad (4-2)$$

The reliability or availability of unit l is an approximated probability value as discussed in the previous chapter and is given by

$$A_l = P(A) = e^{\frac{-\tau}{MTTF}} \quad (4-3)$$

The unavailability of unit l is, therefore, an approximated probability value given by

$$U_l = P(U) = 1 - A_l = 1 - e^{\frac{-\tau}{MTTF}} \quad (4-4)$$

where

τ a lead time variable [h].

Rapid-start units allocated with non-spinning reserve (NR) are required to deliver their reserve contribution during contingency. When outage occurred, the system frequency will dip suddenly. At that moment, the electric generation supply is less than the system demand. If there is insufficient reserve to arrest this dip in frequency, the unbalance in supply and demand may cause a further unit outage which may lead to a system collapse. The starting reliability of rapid-start units has become a major concern as reserve is needed quickly to arrest the frequency drop and avoid system collapse but units may not be able to start up successfully. The table below shows the probability events of rapid-start units using the joint probability distribution approach [176].

Table 4-1 Probability events on rapid-start units

		Operating Probability	
		Availability, $P(A)$	Unavailability, $P(U)$
Starting Probability	Success, P_l^{SS}	$P_l^{SS} \cdot P(A)$	$P_l^{SS} \cdot P(U)$
	Failure, P_l^{SF}	$P_l^{SF} \cdot P(A)$	$P_l^{SF} \cdot P(U)$

From Table 4-1, the column events are the operating probability of the rapid-start unit and the row events are the starting probability of the unit. The summation of the products of these events probabilities is

$$P_l^{SS} \cdot P(A) + P_l^{SF} \cdot P(A) + P_l^{SS} \cdot P(U) + P_l^{SF} \cdot P(U) = 1 \quad (4-5)$$

When the rapid-start unit is allocated with NR, equation (4-3) is reformulated as

$$A_l = P_l^{SS} \cdot P(A) = P_l^{SS} \cdot e^{\frac{-\tau}{MTTF}} \quad (4-6)$$

This is the product of success in starting probability and the availability of the unit in operation. The unavailability of the unit l expressed in equation (4-4) considering the start up failure is reformulated by rearranging equation (4-5) as

$$U_l = P_l^{SF} \cdot P(A) + P_l^{SS} \cdot P(U) + P_l^{SF} \cdot P(U) = 1 - P_l^{SS} \cdot e^{\frac{-\tau}{MTTF}} \quad (4-7)$$

4.2.2 Modelling of Expected Energy Not Served

In this work, the EENS is a function of the unit's probability of failure during the study time. For an electric power system comprising conventional thermal units and rapid-start units, the loss of load probability ($LP_{i,t}$) and loss of load amount ($LC_{i,t}$) for a single online unit outage are

$$LP_{i,t} = \prod_{l=1}^{NRS} A_l \cdot \prod_{l=1; l \neq i}^U A_l \cdot \prod_i (1 - A_i) \quad (4-8)$$

$$LC_{i,t} = Load_i - \sum_{l=1; l \neq i}^U (P_{l,t} + R_{l,t}) - \sum_{l=1}^{NRS} R_{l,t}^{rs} \quad (4-9)$$

where

NRS	number of offline rapid-start units
U	total number of online generation units
$Load_t$	system demand at hour t [MW]
$P_{l,t}$	MW generation from unit l at hour t [MW]
$R_{l,t}$	MW reserve allocated to unit l at hour t [MW]
$R_{l,t}^{rs}$	NR allocated to offline rapid-start unit l at hour t [MW]
l	index for energy and reserve providers.

The sum of total capacity of generation units and total reserve from the offline rapid-start unit is

$$TCR = \sum_{l=1}^U (P_{j,t} + R_{j,t}) + \sum_{l=1}^{NRS} R_{l,t}^{rs} \quad (4-10)$$

where

$P_{i,t}$ MW generation from online unit i at hour t [MW]

$R_{i,t}$ MW reserve from the online unit i at hour t [MW].

The general expression for EENS is the product of the equations (4-8) and (4-9), i.e. $EENS_{i,t} = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t}$ under a single contingency caused by the outage of online unit i . The term $\theta_{i,t}$ and higher order outages for EENS values are given in Chapter 3.

A. *Rapid-Start Units Selected for Non-Spinning Reserve Allocation*

Offline rapid-start units are not in operation yet when their services are called for. The EENS for the units is actually the allocated NR quantity that failed to convert to energy when required. This is different from the concepts of EENS for the online unit, where the allocation is the energy and reserve not served due to its outage.

The general formulation of the EENS for the rapid-start units with NR reserve allocation is

$$EENS_{com,t}^{WNR} = EENS_{com,t}^{-RSU} + EENS_{com,t}^{RLT} - EENS_{com,t}^{+RSU} \quad (4-11)$$

where

WNR EENS superscript indicates that the system has rapid-start unit(s) allocated with NR

com EENS subscript, a set that comprises outage orders of different energy and reserve providers at hour t , i.e.

$com = \{i, (k, i), (k, i, j), (j, k, i)\}$ and (i, j, k) are the indices for energy and reserve providers.

The three components on the right-hand side of equation (4-11) are,

(i) $EENS_{com,t}^{-RSU}$: EENS for period $[0, SRT]$ where SRT is the 10-minute ORR timing before the rapid-start unit is initiated and connected to the system. The unit reliability is computed with P_i^{SS} equal to unity since only the online generation units will be considered in the EENS calculation as the unit is not yet connected to the network for reserve contribution. This time gap indicates the absence of these rapid-start unit(s) that allocated with NR.

(ii) $EENS_{com,t}^{+RSU}$ and $EENS_{com,t}^{RLT}$: Two EENS components considering the start up failures of rapid-start units allocated with NR. The first component in this hour is calculated up to SRT and the latter up to LT . Their unit reliabilities are computed using equation (4-6). These two components are computed to obtain the un-served energy quantity which is the difference between the two components when the offline rapid-start units are connected.

When NR is allocated to rapid-start units in the system, the contribution of EENS from outage orders of online units is re-formulated as follows,

$$EENS_{i,t}^{WNR} = EENS_{i,t}^{-RSU} + EENS_{i,t}^{RLT} - EENS_{i,t}^{+RSU} \quad (4-12a)$$

$$EENS_{i,j,t}^{WNR} = EENS_{i,j,t}^{-RSU} + EENS_{i,j,t}^{RLT} - EENS_{i,j,t}^{+RSU} \quad (4-12b)$$

$$EENS_{i,j,k,t}^{WNR} = EENS_{i,j,k,t}^{-RSU} + EENS_{i,j,k,t}^{RLT} - EENS_{i,j,k,t}^{+RSU} \quad (4-12c)$$

These EENS is computed by replacing τ in equation (4-6) with two timings: SRT and LT . The 10-minute timing (SRT) represents the time it takes for the unit to get synchronised and connected, and the 1-hour time (LT) represents the time it takes for the unit to contribute energy. The first order EENS terms of equation (4-12a) are formulated as

$$EENS_{com,t}^{-RSU} = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t} \Big|_{-RSU} \quad (4-13a)$$

$$EENS_{com,t}^{RLT} = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t} \Big|_{RLT} \quad (4-13b)$$

$$EENS_{com,t}^{+RSU} = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t} \Big|_{+RSU} \quad (4-13c)$$

where

- RSU* a system with zero NR allocated to rapid-start unit(s) and computed up to *SRT*
- RLT* a system with NR allocated to rapid-start unit(s) and computed up to *LT*
- +*RSU* a system with NR allocated to rapid-start unit(s) and computed up to *SRT*. Equations (4-13b) to (4-13c) are computed with compositions of different sources and timings.

The EENS due to outage of online units is therefore written as

$$EENS_t^S = \sum_{i=1}^U EENS_{i,t}^{WNR} + \sum_{i=1}^U \sum_{j>i}^U EENS_{i,j,t}^{WNR} + \sum_{i=1}^U \sum_{j>i}^U \sum_{k>j}^U EENS_{i,j,k,t}^{WNR} \quad (4-14)$$

Equation (4-14) can be pictorially represented by an area ABCDEFGA of Fig. 4-1. This is a plot on the expected loss of load over time. The area under the plot is an EENS value. Over the time horizon of LT, energy recovery occurs when the lost generation is replaced.

When offline rapid-start units are called in for energy contribution during a contingency, they may take 10 minutes (*SRT*) to start up, synchronise and connect to the network. During *SRT*, no energy is supplied by these units. Hence, the EENS area to the left of *SRT* in Fig. 4-1 remains the same. If these units are perfectly reliable, energy recovery from them without any failure is represented by area BEDCB, else energy recovery will be area BECB with failure in starting some of the units.

Figure 4-1 Area plot of system with thermal units and rapid-start unit(s) showing EENS contribution with/without rapid-start units allocated with non-spinning reserve

The EENS due to failure of the rapid-start units in converting NR to energy is simplified from equation (4-11) by discarding its first term $EENS_{com,t}^{-RSU}$ since this term, i.e. the first term in equation (4-12a) and the associated higher order $-RSU$ terms in equations (4-12b) and (4-12c), has been computed in equation (4-14). Hence, equation (4-11) is simplified to become

$$EENS_{com,t}^{WNR} = EENS_{com,t}^{RLT} - EENS_{com,t}^{+RSU} \quad (4-15)$$

The computation of $EENS_{com,t}^{+RSU}$ and $EENS_{com,t}^{RLT}$ of equation (4-15) is similar to that of equations (4-13b) and (4-13c) respectively. The EENS due to the failure of the rapid-start unit(s) after outage(s) of online unit(s) using equation (4-15) is

$$EENS_t^O = \sum_{k=1}^{NRS} \sum_{i=1}^U EENS_{k,i,t}^{WNR} + \sum_{k=1}^{NRS} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^{WNR} + \sum_{j=1}^{NRS} \sum_{k>j}^{NRS} \sum_{i=1}^U EENS_{j,k,i,t}^{WNR} \quad (4-16)$$

This equation is pictorially represented by the area CEDC of Fig. 4-1.

The total EENS is then the summation of the expected energy not served from outages of committed units ($EENS_t^S$) and the rapid-start units which failed during starting up ($EENS_t^O$) for system comprising of conventional thermal units and rapid-start units. The expected energy not served for period t is

$$EENS_t = EENS_t^S + EENS_t^O \quad (4-17)$$

This equation is the EENS caused by online units and rapid-start units which is the area ABCEFGA of Fig. 4-1.

B. Rapid-Start Units Not Selected for Non-Spinning Reserve Allocation

During contingency, a single or higher order outage on online units may happen. Loss of load may occur. Therefore, EENS due to the outage of online unit(s) when zero NR has been allocated to rapid-start units is

$$EENS_t^S = \sum_{i=1}^U EENS_{i,t}^{ZNR} + \sum_{i=1}^U \sum_{j>i}^U EENS_{i,j,t}^{ZNR} + \sum_{i=1}^U \sum_{j>i}^U \sum_{k>j}^U EENS_{i,j,k,t}^{ZNR} \quad (4-18)$$

and

$$EENS_{i,t}^{ZNR} = \theta_{i,t} \cdot LP_{i,t} \cdot LC_{i,t} \quad (4-19a)$$

$$EENS_{i,j,t}^{ZNR} = \theta_{i,j,t} \cdot LP_{i,j,t} \cdot LC_{i,j,t} \quad (4-19b)$$

$$EENS_{i,j,k,t}^{ZNR} = \theta_{i,j,k,t} \cdot LP_{i,j,k,t} \cdot LC_{i,j,k,t} \quad (4-19c)$$

where

ZNR EENS superscript reflects the system with zero (no) NR allocated to rapid-start units. The lead time τ in equation (4-6) is set to 1-hour lead time (LT), i.e. $\tau = LT$ and starting reliability P_i^{SS} is unity.

Equation (4-18) is shown pictorially in Fig. 4-1 with the area ABEFGA, where it forms the main EENS plot of unit contingency. The expected energy not served at period t is therefore equal to equation (4-18).

4.2.3 Objective Function

With additional reserve providers such as rapid-start units, additional terms have to be included in the objective function.

$$\begin{aligned} \text{Min} \left\{ \sum_{t=1}^T \sum_{i=1}^U \left[C_i^E(P_{i,t}, MC_{i,s}, u_{i,t}) + cr_i^{SU} \cdot u_{i,t} (1 - u_{i,t-1}) + C_i^{SR}(cr_i^{SR}, R_{i,t}, u_{i,t}) \right] \right. \\ \left. + \sum_{t=1}^T \sum_{i=1}^{NRS} C_i^{rs}(cr_i^{rs} \cdot R_{i,t}^{rs} \cdot (1 - u_{i,t}^{rs})) + \sum_{t=1}^T EENS_t \cdot VOLL \right\} \quad (4-20) \end{aligned}$$

where

T	total number of hours in the time period
C_i^{rs}	cost of reserve from offline rapid-start unit i [\$/h]
C_i^E	cost of output power from committed unit i [\$/h]
C_i^{SR}	cost of spinning reserve from committed unit i [\$/h]
cr_i^{SU}	start up cost for unit i [\$/h]
cr_i^{SR}	reserve bidding price from online unit i [\$/MWh]
cr_i^{rs}	NR bidding price from offline rapid-start unit i [\$/MWh]
$MC_{i,s}$	Marginal cost in the s^{th} segment of the piecewise linear cost curve of unit i [\$/MWh]
$u_{i,t}$	status of unit i at hour t (1 when committed and 0 otherwise)
$u_{i,t}^{rs}$	status of rapid-start unit i at hour t (1 when committed as normal online unit and 0 otherwise)
$VOLL$	value of lost load [\$/kWh].

The UC problem is subjected to the same constraints as those in Chapter 3 except for the 10-minute ORR with the summation of $\sum_{i=1}^{NRS} R_{i,t}^{rs}$ added in (3-26) and the following constraint which governs the NR amount allocated to rapid-start units.

$$R_{i,t}^{rs} = \min\left\{P_i^{rs,max}, \max\left(P_i^{rs,min}, RUR_i^{rs} \cdot 10/60\right)\right\} \quad (4-21)$$

where

$P_i^{rs,max}$ rapid-start unit i maximum capacity [MW]

$P_i^{rs,min}$ rapid-start unit i minimum capacity [MW]

RUR_i^{rs} ramp up rate of rapid-start unit i [MW/h].

Rapid-start units, OCGTs, will be modelled as conventional thermal units when they are scheduled for energy and SR, i.e. $U = TH + NGT$ where TH is the total number of thermal units and NGT is the total number of OCGTs.

4.2.4 Simulation Results on Systems with Rapid-Start Units

In this sub-section, the simulation of OCGTs which incorporates their starting reliability is performed. The results are then studied by comparing with those of two other systems: base case system with conventional thermal units without OCGT and system with OCGTs but without considering starting reliability.

The base case is the same system as in Chapter 3. For the system with OCGTs, units 6 to 9 of the base case are replaced by four OCGTs. The only change is that the ramp up/down rate of the thermal units which now represent OCGTs is raised to obtain per minute a MW ramping value at 10% of the installed capacity. Both the offer prices spinning and non-spinning reserves are set to 10% of their maximum energy offer prices. The system demand over a 24-hour period is shown in Table A-6. VOLL is set to 4 \$/kWh. Non-spinning reserve is set to 50% of ORR.

A. Determination of Total Cost and Reliability Studies

The optimal total costs for the systems modelled are determined using the CBA approach. The reliability levels used for comparison are obtained at the point where the optimal cost occurs. Fig. 4-2 is a plot on the total cost versus the unreliability for the base case and systems with starting reliability of OCGT varied from 0.94 to 1. A unity starting reliability is equivalent to system modelled without starting reliability and vice versa.

When the system is modelled with OCGTs, the system reliability at optimal cost has improved compared to that of the base case. However, this system reliability begins to deteriorate when modelling of unit starting reliability is accounted for in the algorithm. This can be seen in Fig. 4-2 where the system reliability at optimal cost (indicated with a circle) shifts toward the right-hand side of abscissa when the starting reliability which varies from 0.94 to 0.99 in steps of 0.1 is incorporated. From Fig. 4-3, systems with OCGTs incur a higher schedule cost which comprises energy and reserve costs but a lower EENS cost when compared to the cost from the base case. This happens regardless of the value of the unit starting reliability. However, with starting reliability deteriorates, the EENS cost increases.

Figure 4-2 Total cost versus unreliability level for systems with OCGTs incorporating various starting reliabilities and VOLL = 4 \$/kWh

Figure 4-3 Optimal total costs for all cases with VOLL = 4 \$/kWh

B. Reserve Allocation

This sub-section studies the reserve allocation among the reserve providers. Fig. 4-4 shows a bar-chart of the percentile of reserve allocation. From the figure, the base case has a 100% of the SR allocated to the thermal units since there is no other source that can supply the reserve.

For the system with OCGTs at unity starting reliability, a certain percentile of reserve has been allocated to the offline OCGTs as NR. There is no SR allocated to the OCGTs. All OCGTs are kept offline. With unity starting reliability, the offline OCGTs are reliable. There will not be any failure during starting up of these OCGTs during contingency. Moreover, the offer prices of NR are identical to those of SR in this study. Hence they are highly competitive. If SR is allocated to OCGTs, the increase in total cost is inevitable. The total cost increment is an aggregated cost to maintain the OCGTs in operation and an additional cost to start up OCGTs.

The percentile of NR allocated to the offline OCGTs has not been notably affected and reduced slightly when starting reliability is incorporated in the modelling process. The identical reserve cost is the main reason for this. Nonetheless, when a certain amount of NR is allocated to offline OCGTs, the overall system reliability deteriorates while the EENS cost increases.

Figure 4-4 Reserve allocations among different reserve providers at optimal cost

C. Expected Energy Not Served Contribution

A plot on the EENS contributed from the different energy and reserve providers are presented in Fig. 4-5.

Figure 4-5 Expected energy not served contribution from various providers

Most energy needed to satisfy the system demand constraint is procured from conventional thermal units. Hence, the main contribution of EENS comes from these online units. However, when OCGTs are modelled with their starting reliability taken into consideration, the EENS contribution from the online thermal units is reduced and remains very much constant regardless of variations in starting reliability OCGTs. There is a significant increase in EENS contribution from these OCGTs, particularly when the starting reliability is reduced.

4.3 Modelling of System Comprising Rapid-Start Units with Demand Side Participation

In Chapter 2, the modelling of demand side and its effects on system properties are extensively traversed. When rapid-start units participate in the electricity market for NR contribution, the EENS modelling process needs to be modified.

4.3.1 Modelling of Expected Energy Not Served

When demand side participates in an electricity market comprising conventional thermal units and rapid-start units, the loss of load probability (LP_i) and loss of load amount (LC_i) for a single online unit outage are

$$LP_{i,t} = \prod_{l=1}^{NIL} A_{l,t} \cdot \prod_{l=1}^{NRS} A_l \cdot \prod_{l=1; l \neq i}^U A_l \cdot \prod_i (1 - A_i) \quad (4-22)$$

$$LC_{i,t} = Load_i - \sum_{l=1; l \neq i}^U (P_{l,t} + R_{l,t}) - \sum_{l=1}^{NIL} R_{l,t}^{ils} - \sum_{l=1}^{NRS} R_{l,t}^{rs} \quad (4-23)$$

and the sum of total capacity is reformulated with an additional term from DSAs,

$$TCR = \sum_{l=1}^U (P_{l,t} + R_{l,t}) + \sum_{l=1}^{NIL} R_{l,t}^{ils} + \sum_{l=1}^{NSR} R_{l,t}^{rs} \quad (4-24)$$

where

NIL total number of DSAs

$R_{l,t}^{ils}$ reserve offer from DSA l at hour t [MW]

A. Rapid-Start Units Selected for Non-Spinning Reserve Allocation

Immediately after outages of online unit(s), ILs may be called in for their services and this depends on the severity of the contingency. However, the malfunction of the UFRs or SCADA may result in ILs not responding when required. The formulation of EENS contributed from ILs is

$$EENS_t^{IL} = \sum_{k=1}^{NIL} \sum_{i=1}^U EENS_{k,i,t}^{WNR} + \sum_{k=1}^{NIL} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^{WNR} + \sum_{j=1}^{NIL} \sum_{j>k}^{NIL} \sum_{i=1}^U EENS_{j,k,i,t}^{WNR} \quad (4-25)$$

and the EENS contribution from rapid-start units is rewritten as

$$EENS_t^O = \sum_{k=1}^{NRS} \sum_{i=1}^U EENS_{k,i,t}^{WNR} + \sum_{k=1}^{NRS} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^{WNR} + \sum_{j=1}^{NRS} \sum_{k>j}^{NRS} \sum_{i=1}^U EENS_{j,k,i,t}^{WNR} \\ + \sum_{k=1}^{NRS} \sum_{i=1}^U \sum_{h=1}^{NIL} EENS_{k,i,h,t}^{WNR} \quad (4-26)$$

where h is the index for energy and reserve provider.

Equation (4-25) is delineated by two combined areas of Fig. 4-6. These areas are MCDLM and CGDC which are computed with different lead times. The area EGFE is the EENS caused by the failing to convert NR into energy by rapid-start units as expressed in equation (4-26).

The total EENS is then the summation of additional EENS term from ILs that failed to disconnect from the network ($EENS_t^{IL}$). The expected energy not served for period t is

$$EENS_t = EENS_t^S + EENS_t^{IL} + EENS_t^O \quad (4-27)$$

This equation is the EENS caused by online units, ILs and rapid-start units represented by the area MCDEGHIJKLM of Fig. 4-6.

B. *Rapid-Start Units Not Selected for Non-Spinning Reserve Allocation*

When the system comprises rapid-start units but there is no NR allocated to them, the formulation of EENS for ILs is

$$EENS_t^{IL} = \sum_{k=1}^{NIL} \sum_{i=1}^U EENS_{k,i,t}^{ZNR} + \sum_{k=1}^{NIL} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^{ZNR} + \sum_{j=1}^{NIL} \sum_{j>k}^{NIL} \sum_{i=1}^U EENS_{j,k,i,t}^{ZNR} \quad (4-28)$$

This equation is represented by area MCGDLM of Fig. 4-6. All components in the equation is computed with a single lead time value of $\tau = LT$, which is the same as what has been discussed in *Section 4.2.2 B* for online units.

Since there is no NR allocated to rapid-start unit, there will not be any EENS contributed from these units. The term $EENS_t^O$ will be equal to zero. Equation (4-27) will thus become a summation of the two EENS terms: $EENS_t^S$ and $EENS_t^{IL}$, which is exactly the same as that derived in Chapter 3. This summation EENS is delineated by the area MCGHIJKLM of Fig. 4-6. A flow chart which depicts the EENS calculation process is shown in Fig. 4-7. A detailed description on the area plot of EENS is tabulated in Table 4-2.

Figure 4-6 Area plot showing EENS contributions from outages on online units, ILs and rapid-start units

Figure 4-7 Flow chart illustrating computation of EENS terms

Table 4-2 Area description of EENS plot shown in Fig. 4-6

Area	Description
ABGHIJKLMA	EENS caused by online unit(s), i.e. equation (4-14).
MCGDLM	EENS caused by ILs, i.e. equation (4-28) and is equivalent to summation of areas MCDLM and CGDC which is EENS caused by ILs, i.e. equation (4-25).
EFGE	EENS caused by rapid-start unit(s) which failed to start-up for NR contribution, i.e. equation (4-26).
MCDEGHIJKLM	EENS caused by online units, ILs and rapid-start unit(s), i.e. equation (4-27).
ABGCMA	Energy recovery from ILs with other IL(s) failed to respond.
ABGDLMA	Energy recovery from ILs without any failure in ILs.
CDEGC	Energy recovery from rapid-start unit(s) with other start-up failures in NR reserve contribution.
CDEFGC	Energy recovery from rapid-start unit(s) without any failure from these units in NR reserve contribution.
ABCDEFGHIJKLMA	EENS computed without considering rapid-start unit(s) allocated with NR. The EENS is computed with SRT , e.g. equation (4-13a).
LDEFIJKL	EENS computed with rapid-start unit(s) allocated with NR. The EENS is computed with SRT , e.g. (4-13c).

4.3.2 Objective Function

With demand side participating in the electricity market, the objective function has to consider the MW block offered from DSAs and their bidding prices in the optimisation process. The objective function is therefore reformulated as

$$\begin{aligned}
 Min \left\{ \sum_{t=1}^T \sum_{i=1}^U \left[C_i^E(P_{i,t}, MC_{i,s}, u_{i,t}) + cr_i^{SU} \cdot u_{i,t} (1 - u_{i,t-1}) + C_i^{SR}(cr_i^{SR}, R_{i,t}, u_{i,t}) \right] \right. \\
 \left. + \sum_{t=1}^T \sum_{i=1}^{NRS} C_i^{rs}(cr_i^{rs} \cdot R_{i,t}^{rs} \cdot (1 - u_{i,t}^{rs})) + \sum_{t=1}^T \sum_{i=1}^{NIL} C_i^{ils}(R_{i,t}^{ils}, B_i^{ils}, u_{i,t}^{ils}) + \sum_{t=1}^T EENS_t \cdot VOLL \right\}
 \end{aligned}
 \quad (4-29)$$

where

C_i^{ils}	cost of reserve from DSA i [\$/h]
B_i^{ils}	Reserve price offered by DSA i [\$/MWh]
u_i^{ils}	status of DSA i at hour t (1 indicates allocated with reserve and 0 otherwise)

4.3.3 Simulation Results on Extended Studies of Rapid-Start Units

The variation of NR bidding prices and capacity of rapid-start units, OCGTs, are performed to traverse their effects on system reliability and economics. Competition among OCGTs with different parameters has also been studied. The system modelled comprises conventional thermal units, OCGTs and ILs. The SR and NR bidding prices of OCGTs are set to 10% of their maximum energy offer prices, otherwise are stated in the case study. Non-spinning reserve is set to 50% of ORR. VOLL is set to 4 \$/kWh.

A. *Variation of Non-Spinning Reserve Offer Prices*

Four case studies are set up to scrutinise the effect of different NR offer prices on the electricity market. A variation of OCGT prices has been manipulated in these studies and they are shown as follows:

Case 1: The price is set to 10% of their maximum energy offer price.

Case 2: The price is set to 50% less than that of Case 1.

Case 3: The price is set to 50% more than that of Case 1.

Case 4: The price is set to 100% more than that of Case 1.

The results of these cases are compared among each other and the system with ILs. Meanwhile, the plots of the total cost for the base case, i.e. system with only conventional thermal unit, together with the plots for the thermal systems with ILs and all the four cases are also shown in Fig. 4-8. Table 4-3 shows the reserve procured with various costs at optimal cost for these cases.

A reduction in the NR offer price from OCGTs will cause the optimal total costs to decrease. This is illustrated with the price from Case 4 which has the highest offer price. The price has been reduced in Case 3 and then to Case 1. With a lower NR price, more reserve is allocated to OCGTs and this elucidates the reduction in the total cost. In addition, the system becomes more reliable as illustrated by Cases 4, 3 and 1 of Fig. 4-8.

Figure 4-8 Total cost versus unreliability level at $VOLL = 4$ \$/kWh with variation of NR offer prices from OCGTs

Table 4-3 Reserve procured and various cost incurred at optimal cost with variation of NR offer prices from OCGTs

	System with ILs	Case 1	Case 2	Case 3	Case 4
Reserve (MW)	4628	8291	7329	7814	4629
Schedule Cost (\$)	715,999	743,656	728,878	742,656	715,890
EENS Cost (\$)	49,807	14,240	24,855	19,033	49,806
Total Cost	765,807	757,897	753,733	761,689	765,696

B. Variation of OCGT Capacity

Another four case studies are simulated to study the effect of different unit capacity of OCGTs in the electric power system. A variation on the P^{max} has been manipulated in this study and is shown below.

Case 1: The P^{max} is set according to Table A-2.

Case 2: The P^{max} is set to twice the value of Case 1.

Case 3: The P^{max} is set to triple of Case 1.

Case 4: The P^{max} is set to four times the value of Case 1.

The replacement of higher capacity OCGTs is able to reduce the optimal total cost but a higher reserve amount needs to be procured. This is shown in Fig. 4-9 and Table 4-4. The schedule cost reduces with the increase in OCGT capacity. The system reliability will be enhanced up to a certain extended maximum limit. A further replacement of higher capacity OCGTs will not improve the system reliability

further. This is illustrated in Case 4. The influence of poor operation reliability (MTTF = 450h) of OCGTs and low starting reliability of OCGTs on system reliability is augmented when the capacity increases to a certain value.

Figure 4-9 Total cost versus unreliability level at VOLL = 4 \$/kWh with variation of OCGT capacity

Table 4-4 Reserve procured and various costs incurred with variation of OCGT capacity

	System with IIs	Case 1	Case 2	Case 3	Case 4
Reserve (MW)	4628	8291	8464	9566	8962
Schedule Cost (\$)	715,999	743,656	735,407	739,683	732,615
EENS Cost (\$)	49,807	14,240	14,315	5,656	10,461
Total Cost	765,807	757,897	749,724	745,338	743,076

C. Competition of OCGTs in Electricity Market

A total of eight OCGTs are modelled to study the effect of various costs and reserve procured, as well as the selection of OCGTs for energy, spinning and non-spinning reserve scheduling. The first four OCGTs are modified from the 26-thermal unit (units 6 to 9) data. The additional OCGTs which are duplicated from the first four OCGTs are modelled as units 27 to 30 in the system. The 30 generation units are modelled together with three DSAs. The OCGTs are divided into two groups: (1) Low Availability (LA) which includes units 6 to 9 with low MTTF values and high

start up failure probabilities; and (2) High Availability (HA) which includes units 27 to 30 with high MTTF values and low start up failure probabilities. Two cases are set up for the study. Case 1 contains all the eight OCGTs offering identical NR prices while Case 2 contains the LA units 6 to 9 with prices lower than those of the HA units. The data is shown in Table A-7. The offer prices of energy and SR for OCGTs are the same for both cases. VOLL is set to 4 \$/kWh. The total cost plots for the two cases are shown in Fig. 4-10. The status of the OCGTs at optimal cost for Case 1 and Case 2 are shown in Table 4-5. Table 4-6 illustrates the MW amount of energy and reserve scheduled to the OCGTs.

Figure 4-10 A plot on the total cost versus unreliability level at VOLL = 4 \$/kWh for two OCGT case studies

Case 1 in Table 4-5 shows that only the HA units are scheduled for both types of reserve. The LA OCGTs, low in both start up and operation reliabilities, have not been selected. For Case 2, the OCGTs with low NR prices are allocated with NR in most hours, while the HA OCGTs are allocated with SR owing to higher operating reliability.

From Fig. 4-10, the optimal cost in Case 2 is obtained at a higher reliability level than that of Case 1. Thus, more reserve is needed as shown in Table 4-7.

Table 4-5 UC scheduled for OCGTs at optimal cost

Case 1: Identical offering prices for non-spinning reserve																											
Unit		Period																									
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
6	LA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
27	HA	0	0	0	0	0	0	0	0	S	S	S	S	N	N	N	N	N	N	0	0	N	N	N	0	0	
28		0	0	0	0	0	0	0	0	0	N	0	0	0	0	0	0	0	0	0	0	0	0	N	0	0	
29		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Case 2: Different offer prices for non-spinning reserve																											
6	LA	0	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	
7		0	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0	
8		0	0	0	0	0	0	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	
9		0	0	0	0	0	0	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0	
27	HA	0	0	0	0	0	0	0	0	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S	0	0	
28		0	0	0	0	0	0	0	0	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S	0	0	
29		0	0	0	0	0	0	0	0	S	S	S	S	0	0	0	0	0	0	N	N	N	N	N	0	0	
30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0 – Off status; S – Unit online with spinning reserve; and N – Unit offline with non-spinning reserve																											

Table 4-6 Energy schedule/reserve allocation for OCGTs at optimal cost

Case 1: Identical offer prices for non-spinning reserve													
		Period											
		1	2	3	4	5	6	7	8	9	10	11	12
6	LA	0	0	0	0	0	0	0	0	0	0	0	0
7		0	0	0	0	0	0	0	0	0	0	0	0
8		0	0	0	0	0	0	0	0	0	0	0	0
9		0	0	0	0	0	0	0	0	0	0	0	0
27	HA	0	0	0	0	0	0	0	4/16	4/16	4/16	4/16	20
28		0	0	0	0	0	0	0	0	20	0	0	0
29		0	0	0	0	0	0	0	0	0	0	0	0
30		0	0	0	0	0	0	0	0	0	0	0	0
Case 2: Different offering prices for non-spinning reserve													
6	LA	20	20	20	20	20	20	20	20	20	20	20	20
7		20	20	20	20	20	20	20	20	20	20	20	20
8		0	0	0	0	0	20	20	20	20	20	20	20
9		0	0	0	0	0	0	20	20	20	20	20	20
27	HA	0	0	0	0	0	0	0	4/16	4/16	4/16	4/16	4/16
28		0	0	0	0	0	0	0	4/16	4/16	4/16	4/16	4/16
29		0	0	0	0	0	0	0	4/16	4/16	4/16	4/16	0
30		0	0	0	0	0	0	0	0	0	0	0	0

Table 4-6 (Cont.) Energy schedule/reserve allocation for OCGTs at optimal cost

Case 1: Identical offer prices for non-spinning reserve													
		Period											
		13	14	15	16	17	18	19	20	21	22	23	24
6	LA	0	0	0	0	0	0	0	0	0	0	0	0
7		0	0	0	0	0	0	0	0	0	0	0	0
8		0	0	0	0	0	0	0	0	0	0	0	0
9		0	0	0	0	0	0	0	0	0	0	0	0
27	HA	20	15.90	20	20	15.90	0	0	15.90	20	20	0	0
28		0	0	0	0	0	0	0	0	0	15.27	0	0
29		0	0	0	0	0	0	0	0	0	0	0	0
30		0	0	0	0	0	0	0	0	0	0	0	0
Case 2: Different offering prices for non-spinning reserve													
6	LA	20	20	20	20	20	20	20	20	20	20	20	20
7		20	20	20	20	20	20	20	20	20	20	20	0
8		20	20	20	20	20	20	20	20	20	20	20	0
9		20	20	20	20	20	20	20	20	20	20	20	0
27	HA	4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	0	0
28		4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	4/16	0	0
29		0	0	0	0	0	0	20	20	20	20	0	0
30		0	0	0	0	0	0	0	0	0	0	0	0

- MW of energy scheduled/spinning reserve allocated; and # - MW of non-spinning reserve allocated

Table 4-7 Reserve Allocation among different turbine types

Case	Spinning Reserve (MW)			Non-Spinning Reserve (MW)	Sub-Total Spinning Reserve (MW)	Sub-Total Non-Spinning Reserve (MW)	Total Reserve (MW)
	Thermal Units	Online OCGTs	ILs (MW)	Offline OCGTs (MW)			
1	3251	64	1320	203	4635	203	4838
2	3807	544	1320	1720	5671	1720	7391

The total reserve procured over the 24-hour period has increased when OCGTs of lower reliability offered a lower NR price. A significant amount of NR is allocated OCGTs of lower price. These LA OCGTs in Case 2 is more competitive than HA units and other expensive conventional thermal units. When more reserve is allocated to cheaper but less reliable units, a higher amount of reserve is needed by the system in order to maintain the system reliability. Fig. 4-11 depicts the breakdown of the optimal costs for the two cases.

Figure 4-11 Total energy, reserve and EENS cost plot for the two 24-hour case studies

Fig. 4-12 shows the bar-chart of the schedule cost for each OCGT over the 24-hour study period for both cases. For units with identical price, unit reliability has a considerable influence on the selection and allocation of energy and reserve. However,

the offer price for energy and reserve is still the major factor to be considered in the electricity market for energy and reserve procurement.

Figure 4-12 Cost of individual OCGT over the 24-hour period: (a) Case 1: Identical NR offer prices from LA and HA OCGTs; (b) Case 2: Lower NR offer prices from LA OCGTs

4.4 Penalty Imposed on Failures of Rapid-Start Units

During contingencies, selected reserve providers are to provide the necessary MW to alleviate the loss of load. Failure to do so may aggravate the incidence of loss of load. Providers who failed to supply the reserve will need to be penalised. This section presents a penalty cost formulation to be imposed on those rapid-start units (RSUs) that failed to start up successfully for reserve contribution during contingencies.

The NR amount, offer price and the starting reliability of RSUs are considered in the formulation. A unit proportional share factor ($UPS_{i,t}$) for failed RSU i at hour t is formulated to calculate the share responsibility among those RSUs that failed to start up for reserve contribution.

$$UPSF_{i,t} = \frac{R_{i,t}^{rs} \cdot C_i^{rs} \cdot (1 - P_i^{SS})}{\sum_{l \in RSF} R_{l,t}^{rs} \cdot C_l^{rs} \cdot (1 - P_l^{SS})} \quad (4-30)$$

where

RSF a set comprises RSUs which failed to start up for NR contribution during hour t .

A system total penalty cost ($STPC_t$) at hour t can be computed as a product of actual outage MW ($AOMW_t$) at hour t and VOLL. It is formulated as shown below:

$$STPC_t (\$) = AOMW_t \cdot VOLL \quad (4-31)$$

The penalty cost ($PC_{i,t}$) for RSU i that failed to convert reserve into energy at hour t is

$$PC_{i,t} (\$) = \frac{EENS_t^O}{EENS_t} \cdot UPSF_{i,t} \cdot STPC_t \quad (4-32)$$

Equation (4-32) is used after an outage occurred. Tables 4-8 to 4-10 depict the penalty that RSUs are penalised for if their services cannot be realised. As the EENS is a function of unit's probability of failure during the study time, the illustration of (4-32) is done by assuming that RSUs failed to start up and an actual load lost is recorded as shown in the two tables.

Table 4-8 Penalty on RSUs with starting reliability of 0.95 at hour 24

RSUs Failed	$EENS_{24}^O$ (kWh)	$EENS_{24}$ (kWh)	Actual Outage MW	Penalty (\$) on RSU, $PC_{i,24}$	
				6	8
6	4.6763	98.83	0.133	25.17	-
8	4.6763	98.83	0.133	-	25.17
6, 8	9.6504	103.80	0.153	28.34	28.55

Table 4-9 Penalty on RSUs for system in *Section 4.3.3 C* Case 1 at hour 22

RSUs Failed	$EENS_i^o$ (kWh)	$EENS_i$ (kWh)	Actual Outage MW	Penalty (\$) on RSU, FP_i	
				27	28
27	0.6129	177.66	0.213	2.94	-
28	0.5993	177.64	0.208	-	2.81
27, 28	1.2247	178.26	0.228	3.52	2.70

Table 4-10 Penalty on RSUs for system in *Section 4.3.3 C* Case 2 at hour 22

RSUs Failed	$EENS_i^o$ (kWh)	$EENS_i$ (kWh)	Actual Outage MW	Penalty (\$) on RSU, FP_i	
				6	29
6	1.0152	96.07	0.114	4.82	-
29	0.3109	95.37	0.114	-	1.49
6, 29	1.3307	96.39	0.134	5.28	2.12

For RSUs which contribute the same amount of NR and have an identical starting reliability, the failure of these units during start up will be penalised according to the reserve offer prices as depicted in Table 4-8. RSU 8 has a higher NR price among these two failure units. In Table 4-9, RSU 28 offers and contributes less reserve, but has same starting reliability as others, will be penalised less. In Table 4-10, RSU 29 with a higher starting reliability will be penalised less if it failed to start up as compared to unit 6 with a lower starting reliability. Both units contributed the same amount of reserve. Accordingly, the penalty cost will increase when the actual outage MW is higher than the values in the simulation as there is a high VOLL or units have relatively poor starting reliability. This implementation will force GENCOs to maintain their units in the most reliable state to avoid additional cost incurred.

4.5 Summary

In this chapter, an extensive study has been performed for a system modelled with rapid-start units, OCGTs. The system total cost, system reliability, reserve allocation and EENS contribution among the various providers are scrutinised. The reserve bidding

price, operating reliability and capacity of OCGTs are varied to investigate their effects power system reliability and economics. Two cases have been modelled and simulated to study how OCGTs compete for energy scheduling and reserve allocation. A penalty factor for OCGTs failing to convert reserve to energy is then proposed.

The findings show that rapid-start units with poor starting reliability have a direct influence towards energy and reserve procurement costs and EENS cost. System reliability deteriorates when NR is allocated to rapid-start units with poor starting reliability. The reduction in reserve bidding price and the increase in capacity of OCGTs is able to reduce the total system cost. To conclude, the energy and reserve offer prices are still the major factor influencing the selection of energy and reserve providers, while the reliabilities of the providers also have a significant effect on energy and reserve cleared in the electricity market.

Chapter 5

Penetration of Renewable Energy into Conventional Electric Power System

5.1 Introduction

Over the years, the global warming effect has gradually changed the production of electricity from mostly traditional fossil fuel to a greater adoption of renewable energy replacement. In this chapter, hydro electric power and wind energy which represent the two most successful renewable energy sources in the conventional electric power system are studied. The hydro electric power generator which is a type of rapid-start unit is modelled to study its effect on electric power system reliability and economics. This chapter will also scrutinise the penetration of wind energy in the existing conventional thermal unit system. The modelling process has considered the wind energy forecast error, due to the erratic wind flow, and the system demand forecast error in hourly energy and reserve procurement. The effect of wind energy penetration has been studied and a comparison among different mix of energy and reserve providers has been traversed toward the end of the chapter.

5.2 Modelling of Hydro Electric Power Generation Plant

In hydro plant modelling, the discharged water from reservoirs is converted to a electric power output which is then multiplied by the offer price of the hydro unit.

5.2.1 Hydro Power Generation and Constraints

Fig. 5-1 illustrates the conversion of discharge water to electric MW through a piecewise linear characteristic curve of a hydro unit. The hydro unit from each plant is cascaded as shown in Fig. 5-2.

Figure 5-1 A piecewise linear characteristic curve of a hydro unit

Figure 5-2 Hydro plant topology of a river basin

The power generation of each hydro unit [49, 137] is characterised as

$$P_{i,t}^h = P_i^{h,\min} \cdot u_{i,t}^h + \sum_{m=1}^{CS_i} q_{s_{i,m}} \cdot h_{s_{i,m}} \quad (5-1)$$

$$(q_{s_{i,m}} + q_{sr_{i,m}}) \leq q_{s_{i,t}}^{max} \quad (5-2)$$

subjected to hydro unit constraints:

(a) Hydro electric power generation and reserve constraint

$$u_{i,t}^h \cdot (P_{i,t}^h + R_{i,t}^h) \leq P_i^{h,max} \quad t = \{1 \dots T\} \quad (5-3)$$

(b) Reservoir water balance equation

$$W_{i,i+1} = W_{i,t} + J_{i,t} - Q_{i,t} - S_{i,t} + \sum_{j=US_i} (Q_{j,t-v} + S_{j,t-v})$$

$$t = \{1 \dots T\} \quad (5-4)$$

$$QR_{i,t} = W_{i,t} + J_{i,t} - W_i^{min} - Q_{i,t} \quad t = \{1 \dots T\} \quad (5-5)$$

(C) Reservoir volume limits

$$W_i^{min} \leq W_{i,t} \leq W_i^{max} \quad t = \{1 \dots T\} \quad (5-6)$$

(d) Initial (0) and final (T) reservoir volumes

$$W_{i,1} = W_i^0 \quad t = \{1 \dots T\} \quad (5-7)$$

$$W_{i,T} = W_i^T \quad t = \{1 \dots T\} \quad (5-8)$$

(e) Water discharge limits

$$Q_i^{min} \leq Q_{i,t} \leq Q_i^{max} \quad t = \{1 \dots T\} \quad (5-9)$$

$$Q_i^{min} \leq QR_{i,t} \leq Q_i^{max} \quad t = \{1 \dots T\} \quad (5-10)$$

(f) Water spillage constraint

$$S_{i,t} \geq 0 \quad t = \{1 \dots T\} \quad (5-11)$$

where

$P_{i,t}^h$	MW generation for hydro unit i at hour t [MW]
$P_i^{h,min/max}$	minimum/maximum power generation of hydro unit i [MW]
$u_{i,t}^h$	status of hydro unit i at hour t (1 when committed and 0 otherwise)
CS_i	number of characteristic curve segments of hydro unit i
m	index for segments of hydro unit's characteristic curve
$qs_{i,m}$	water discharge for hydro unit i at segment m [Hm ³]
$hs_{i,m}$	slope of segment m for hydro unit i [MW/Hm ³]
$q_{i,m}^{sr}$	water discharge available for hydro unit i in reserve allocation [Hm ³]
$qs_{i,t}^{max}$	maximum water discharge rate for hydro unit i on segment m [Hm ³]
$R_{i,t}^h$	MW reserve allocated to hydro unit i at hour t [MW]
$W_{i,t}$	reservoir volume for hydro unit i at hour t [Hm ³]
$J_{i,t}$	natural inflow to a reservoir for unit i at hour t [Hm ³]
$Q_{i,t}$	water discharge from a reservoir for hydro unit i at hour t [Hm ³]
$S_{i,t}$	spillage of water from a reservoir for hydro unit i at hour t [Hm ³]
US_i	set of upper stream reservoirs of plant i
v	time delay of upper reservoir [h]
$QR_{i,t}$	water discharge for NR from a reservoir for hydro unit i at hour t [Hm ³]
$W_i^{min/max}$	minimum/maximum reservoir's limit for hydro unit i [Hm ³]
W_i^0	initial reservoir's limit for hydro unit i [Hm ³]
W_i^T	final reservoir's limit for hydro unit i [Hm ³]
$Q_i^{min/max}$	minimum/maximum water discharge's limit for hydro unit i [Hm ³ /h].

The total cost of electric power generates from each hydro unit at hour t is

$$C_i^E(P_{i,t}^h, MC_{i,m}, u_{i,t}^h) = P_{i,t}^h \cdot MC_{i,m} \cdot u_{i,t}^h \quad (5-12)$$

and

$$\text{Start up cost} = cr_i^{SU} \cdot u_{i,t}^h \cdot (1 - u_{i,t-1}^h) \quad (5-13)$$

$$\text{Spinning reserve (SR) cost, } C_i^{SR} = cr_i^{SR} \cdot R_{i,t}^h \cdot u_{i,t}^h \quad (5-14)$$

$$\text{Non-spinning (NR) cost, } C_i^{rs} = cr_i^{rs} \cdot R_{i,t}^h \cdot (1 - u_{i,t}^h) \quad (5-15)$$

where

C_i^E	cost of output power from committed unit i [\$/h]
cr_i^{SU}	start up cost of unit i [\$]
cr_i^{SR}	reserve bidding price from committed unit i [\$/MWh]
cr_i^{rs}	NR bidding price from offline rapid-start unit i [\$/MWh]
$MC_{i,m}$	Marginal cost in the m^{th} segment of piecewise linear cost curve of unit i [\$/MWh].

5.2.2 Objective Function

The objective function derived in Chapter 4 for rapid-start units will be used to solve the UC problem where there are hydro power generators in the system. The total number of unit, U , is the sum of thermal unit (TH), OCGTs (NGT) and hydro units (NHY), i.e. $U = TH + NGT + NHY$ and the total number of rapid-start units is the sum of OCGTs and hydro units, i.e. $NRS = NGT + NHY$. These are illustrated in [177]. For hydro units to be scheduled as part of UC, the energy, spinning reserve and unit status variables in equations (5-12) to (5-14) are replaced by the general variables: $P_{i,t}$, $R_{i,t}$ and $u_{i,t}$. For NR allocation, the non-spinning reserve and unit status variables in equation (5-15) are replaced by $R_{i,t}^{rs}$ and $u_{i,t}^{rs}$ respectively.

5.2.3 Simulation Results for Systems with Hydro Electric Power Plants

To demonstrate the effect of offer prices, reliabilities and ramp rates of reserve providers on system economics and reliabilities, eight different case studies are set up. The reserve providers consist of 26 thermal generators (Unit 1-26), 6 hydro generators (Unit 27-32) as RSUs and 3 ILs. The VOLL is set at 4 \$/kWh and the EENS assessment criterion ($EENS_{max}$) is assigned 0.35 MWh. The market clearing engine runs for a period of 24 hours.

- Case 1: 26 thermal units participate in the energy and reserve market (Base Case).
- Case 2: There are 26 thermal units. The MTTF of units 10 to 13 is increased 25-fold. Their unit capacity is less than 100 MW and they are small capacity units in the system.
- Case 3: There are 26 thermal units. The MTTF of units 25 and 26 is increased 25 folds. They are the largest capacity units in the system.
- Case 4: There are 26 thermal units. The ramp up rate of units 10 to 13 is increased two folds.
- Case 5: There are 26 thermal units. The reserve offer price of units 10 to 13 is halved.
- Case 6: There are 26 thermal units. 3 DSAs participate in the 10-minute reserve market.
- Case 7: There are 26 thermal units and 6 hydro units.
- Case 8: There are 26 thermal units and 6 hydro units. 3 DSAs participate in the 10-minute reserve market.

A plot of the operating hours on each unit and IL for the case studies is shown in Fig. 5-3. The costs are tabulated in Table 5-1. It is used to compare the various costs among the cases and the quantities of reserve procured throughout the study period. For Case 2, a

small reserve deviation from Case 1 is shown when the operating reliability values of small thermal units are improved. With 1 MW less reserve procured, the total cost is \$504.5 less than that of the base case. The thermal units are to be committed online for SR contribution. This is different from the earlier study in Chapter 4 where OCGTs offer NR contribution. The increase in MTTF on the two largest thermal units leads to an overall system reliability improvement as demonstrated in Case 3. This is the smallest amount of reserve needed to maintain the system reliability as compared to that of other cases. It can be deduced that large capacity online generators with a small MTTF will make the power system less reliable. A high MTTF value means that the probability of the unit failing during the operation is extremely small. Therefore, the chances of losing these high capacity units during operation are small. From Figs. 5-3 and 5-4, a reduction in the operating hours in Case 4 for expensive units (Units 6 to 9 and 15 to 16) is shown as more reserve has been allocated to units with high ramp rates, and average energy and reserve offer prices.

From Case 5 onwards, the results shown that units with high energy and start up offer prices generally will not be selected. A lower total energy cost can be achieved when ILs are incorporated. Hydro units are able to reduce the total combined costs cutting down the online periods of expensive thermal units. From Table 5-2, it can be seen that the online units are the major EENS contributors. An outage on these committed units may cause lose of load if reserve procured is insufficient. A small EENS amount is contributed from ILs and offline hydro units because of their high operating reliability and mainly due to the fact that their services are required only when unit outage on occurred.

Figure 5-3 3-Dimensional plots of unit operating hour distribution

Figure 5-4 Reserve allocation plots for eight case studies over a 24-hour study horizon

Table 5-1 Comparison of system reserve procured, energy cost, reserve cost, EENS cost and total cost

Study Case	Total Reserve Procured (MW)	Total Energy Cost (\$)	Total Reserve Cost (\$)	Total EENS Cost (\$)	Total Cost (\$)
1	6,107	752,425	10,458	33,722	796,605
2	6,106	751,968	10,432	33,700	796,101
3	3,036	705,094	5,765	33,325	744,184
4	6,158	738,723	10,234	33,268	782,225
5	6,107	752,424	10,010	33,722	796,157
6	6,137	722,624	10,790	33,472	766,886
7	6,215	657,205	11,089	33,455	701,749
8	6,154	653,293	9,850	33,376	696,520

Table 5-2 Breakdown on reserve and EENS contributions for Cases 6-8

Reserve				
Case	Thermal Units (MW)	Hydro Units		ILs (MW)
		SR (MW)	NR (MW)	
6	4817	0	0	1320
7	3504	2231	480	0
8	2866	1908	120	1260
EENS				
Case	Online Units (kWh)	Offline Hydro Units (kWh)		ILs (kWh)
6	8365.20	0		2.87
7	8362.74	1.91		0
8	8340.76	0.48		2.70

5.3 Modelling of Wind Turbine Generator

In this section, the electric power generation from the wind turbine generator (WTG) is first modelled. A novel methodology in the formulation of EENS considering the forecasted errors of load demand and wind generation is proposed. This EENS value is integrated into the objective function of the UC problem. Simulation results of the studies for wind energy penetration and a comparison among the systems with different energy and reserve providers are presented.

5.3.1 Evaluation of Wind Turbine Generator

Fig. 5-5 shows the power curve plot based on the performance of WTG used to illustrate the wind power generation.

Figure 5-5 Typical wind turbine generator output versus wind speed plot

The i^{th} wind unit starts generating power at a wind speed called the cut-in speed V_i^{CI} and it reaches the rated electrical output at a wind speed called the rated speed V_i^R . The rated power $P_i^{W,max}$ is produced when the wind speed varies from V_i^R to the cut-out or furling wind speed V_i^{CO} . Beyond the cut-out speed, the unit is shutdown for safety reasons. The hourly electrical power generation is calculated from the wind speed data using the WTG's power curve. The wind speed is V_t in m/s. The MW power output of WTG i during period t is calculated using the following equation:

$$P_{i,t}^W = K_i(V_t) \cdot \omega_a + P_i^{W,max} \cdot \omega_b \quad (5-16)$$

where $P_i^{W,max}$ is the maximum capacity of WTG i , and ω_a and ω_b are the status of wind speed (1 or 0) set by the following conditions,

ω_a	ω_b	Condition
0	0	$V_t < V_i^{CI} \text{ or } V_t > V_i^{CO}$
1	0	$V_i^{CI} \leq V_t < V_i^R$
0	1	$V_i^R \leq V_t \leq V_i^{CO}$

The function $K_i(V_t)$ which determines the MW generation from the i^{th} wind turbine is

$$K_i(V_t) = \frac{V_t - V_i^{CI}}{V_i^R - V_i^{CI}} \cdot P_i^{W,max} \quad (5-17)$$

The total available MW wind generation at hour t is the summation of MW production of all wind turbine generators,

$$P_{Total,t}^W = \sum_{i=1}^{NWG} P_{i,t}^W \quad (5-18)$$

where NWG is the number of wind turbine generators.

The minimum/maximum available wind generation is

$$0 \leq P_{Total,t}^W \leq \sum_{i=1}^{NWG} P_i^{W,max} \quad (5-19)$$

5.3.2 Determination of Net Forecast Error

The inability of predicting load demand and wind power generation accurately leads to the need to schedule sufficient operating reserve to cover forecast errors due to an unplanned surge in load demand, and/or a sudden drop in wind power generation. The proposed methodology requires the knowledge of forecast errors arising from inaccuracies in predicting load demand and wind power generation. This is needed prior

to the EENS calculation as inaccurate forecast could result in loss of load when the scheduled reserve is not enough to meet an increase in load and/or a decrease in generation.

A. Demand Forecast Errors

Numerous studies on load forecasting have been carried out and the technique has grown toward maturity due to the cyclical nature of load [178]. The standard deviation (MW) of the load forecast error over the forecasting horizon can thus be assumed to be a percentage of the actual load [155] and is reproduced as

$$\sigma_{l,t} = \frac{\alpha}{100} \cdot Load_t \quad (5-20)$$

where

$\sigma_{l,t}$	standard deviation of load at hour t [MW]
α	accuracy of forecast error tool [%]
$Load_t$	system demand at hour t [MW].

B. Wind Forecast Errors

The wind turbines are installed at different sites. The wind error prediction for wind power generation tends to be in a skewed or Beta distribution instead of the bell-shaped normal distribution. The standard deviation of the wind forecast error can be approximated by multiplying the ninety percentiles of the wind power generated by a factor of 0.2 [154, 179]. These percentiles of wind power are assumed since the scheduled values usually cannot be realised as is. A background error of 4% from the installed capacity [180] is then added to the forecast error. This is caused by the imperfection of turbines and measurement errors owing to sub-grid scale weather activities and algorithms used to compute the wind power. The standard deviation (MW) formulated at time t is

$$\sigma_{w,t} = 0.2 \cdot P_{90} + 0.04 \cdot P^{WI} \quad (5-21)$$

where

P_n n^{th} percentile of the total forecast wind power generation, $P_{Total,t}^W$ at hour t [MW]
 P^{WI} total capacity of wind turbines [MW].

C. Net Forecast Errors

The load and wind forecast errors are assumed to be independent and uncorrelated. The standard deviation of the combined errors in MW at hour t is

$$\sigma_{total,t} = \sqrt{\sigma_{l,t}^2 + \sigma_{w,t}^2} \quad (5-22)$$

The advantage of the proposed methodology is that α of (5-20) and the fixed parameter values of 0.2 and 4% of (5-21) can be changed according to technologies advancement. In addition, standard deviations computed from other forecast methods can also be substituted into (5-22) to obtain the total forecast error. The uncertainties associated with system forecast demand and wind flow will change as a function of time and forecast lead time. Hence $\sigma_{l,t}$ and $\sigma_{w,t}$ will change as time advances and according to the accuracy of the forecasting techniques. These standard deviation values obtained from each forecast hour must be applied to the respective hour in the EENS formulation. The computed EENS values will then be used in the UC optimisation problem.

The wind power produced is correlated to wind speed. In (5-21), the total installed capacity of WTGs dominates over the standard deviation of wind power forecast errors when the wind speed is low. When the number of WTGs in the wind farm is small, the standard deviation of the wind power forecast error, $\sigma_{w,t}$, at low wind speeds will be

small when compared to that of the load forecast error, $\sigma_{l,t}$, in (5-20) at high demand. The load forecast error, $\sigma_{l,t}$, will dominate the total forecast error in (5-22). Conversely, the wind forecast error, $\sigma_{w,t}$, will be a dominant factor at high wind speeds when many WTGs supply a low demand load. These observations will be illustrated in a case study conducted in Section 5.3.5.

5.3.3 Formulation of Expected Energy Not Served

A normal distribution curve in Fig. 5-6 is used to represent the forecast error probability that results in loss of load. The shaded region on the right of the figure is the probability that results in loss of load. The un-shaded region is the probability that results in no loss of load. In addition, unit outages may also result in loss of load. This sub-section examines loss of load as affected by the combined effect of forecast errors and unit outages.

Figure 5-6 Normal distribution of net system forecast error at time t

For a total forecast error ($\sigma_{total,t}$) that is greater than the system reserve minus the MW outages of operating units, the forecast error probability that results in loss of load is

$$FP_t = 1 - \Phi\left(\frac{\sum R - \sum Outage\ MW}{\sigma_{total,t}}\right) \quad (5-23)$$

where

$\Phi(\cdot)$	a normalised distribution function
$\sum R$	summation of all available reserve obtained from the reserve providers in the system through the UC solution [MW]
$\sum Outage\ MW$	summation of MW outages of the units and non-dispatchable WTGs that have been scheduled for operation and the summation only considers up to third order outages [MW].

When the forecast error probability is considered for three possible scenarios that may/may not result in loss of load, (5-23) is reformulated as

$$FP_t^f = \begin{cases} \Phi(\cdot), & \text{forecast error probability that results in no loss of load and } f = 1; \\ 1 - \Phi(\cdot), & \text{forecast error probability that results in loss of load and } f \in \{0, 2\}. \end{cases} \quad (5-24)$$

where the superscript f is an index for the forecast error probability of the three system scenarios caused by the severity of the forecast errors and with/without the occurrence of unit outages. The meanings of the three different system scenarios and their forecast error probabilities (FP_t^f) are elucidated in Table 5-3.

The MW value of forecast errors (FCE_t^f) at hour t considering the stochastic nature of a power system is

$$FCE_t^f = \begin{cases} 0, & \text{forecast error that results in no loss of load and } f = 1; \\ FP_t^f \cdot \sigma_{total,t}, & \text{forecast error that results in loss of load (MW) and } f \in \{0, 2\}. \end{cases} \quad (5-25)$$

Table 5-3 Forecast error probability with different f indices

f	Forecast Error Probability, FP_t^f
0	Forecast error probability, FP_t^0 , is meant for a system without unit outage ($\sum \text{Outage MW} = 0$) but the forecast error is so big that it results in loss of load. This is represented by the shaded region in Fig. 5-6.
1	Forecast error probability, FP_t^1 , is meant for a system that unit outages ($\sum \text{Outage MW} > 0$) have occurred but the combined effect of forecast error and unit outages results in no loss of load. This implies that the system is protected from loss of load by a sufficiently large amount of reserve and the total forecast error is not so severe. This is represented by the un-shaded region in Fig. 5-6.
2	Forecast error probability, FP_t^2 , is meant for a system that unit outages ($\sum \text{Outage MW} > 0$) have occurred and the combined effect of forecast errors and unit outages results in loss of load. This is represented by the shaded region in Fig. 5-6.

The load curtailment as a function of forecast errors is written as

$$LC_t^0 = Load_t + FCE_t^0 - \sum_{l=1}^U (P_{l,t} + R_{l,t}) - \sum_{l=1}^{NIL} R_{l,t}^{ils} - \sum_{l=1}^{NRS} R_{l,t}^{rs} \quad (5-26)$$

$$LC_{i,t}^f = Load_t + FCE_t^f - \sum_{l=1; l \neq i}^U (P_{l,t} + R_{l,t}) - \sum_{l=1}^{NIL} R_{l,t}^{ils} - \sum_{l=1}^{NRS} R_{l,t}^{rs}, \quad f \in \{1, 2\} \quad (5-27)$$

where

LC_t^0 load curtailment owing to large net forecast error ($f = 0$) without

	unit outages at hour t . [MW]
$LC_{i,t}^f$	load curtailment with unit i 's outage at hour t when $f \in \{1, 2\}$ [MW]
U	total number of committed units, i.e. $U = TH + NGT + NHY + NWG$
NIL	total number of DSAs
NRS	total number of rapid-start units
$P_{l,t}$	MW generation for unit l at hour t [MW]
$R_{l,t}$	MW reserve allocated to unit l at hour t [MW]
$R_{l,t}^{ils}$	reserve offer from DSA l at hour t [MW]
$R_{l,t}^{rs}$	NR allocated to rapid-start unit l at hour t [MW]
i, l	indices for energy and reserve providers.

Equation (5-27) is computed for a single unit i outage. Having considered the forecast error probability owing to net forecast errors of demand and wind generation, the probability of events is set up for the EENS formulation.

Table 5-4 Probability for total forecast errors and probability for unit availabilities

Probability for Total Forecast Errors	Probability for Unit Availabilities
Loss of load $\rightarrow FP_t^0 = 1 - \Phi(\cdot)$	No unit outage $\rightarrow \prod_{l=1}^U A_l \cdot \prod_{l=1}^{NIL} A_l \cdot \prod_{l=1}^{NRS} A_l$
No loss of load $\rightarrow FP_t^1 = \Phi(\cdot)$	Unit i outages $\rightarrow \prod_{l=1; l \neq i}^U A_l \cdot \prod_{l=1}^{NIL} A_l \cdot \prod_{l=1}^{NRS} A_l \cdot \prod_i (1 - A_i)$
Loss of load $\rightarrow FP_t^2 = 1 - \Phi(\cdot)$	

From Table 5-4, A_l is the reliability of unit l and is the product of P_l^{SS} and $e^{\frac{-\tau}{MTTF}}$. P_l^{SS} is the starting reliability of unit l . If no rapid-start unit is considered, the term is unity. τ is a lead time variable and $MTTF$ is the mean time to failure for unit l . The pair associated

with the forecast error probability results in no loss of load and the probability without unit outage is not included in the table as both probabilities do not result in loss of load.

When there is no unit outage and the total forecast error is high enough to cause loss of load, the probability of loss of load (LP_t^0) for the EENS formulation using the joint probability distribution approach is given by

$$LP_t^0 = FP_t^0 \cdot \prod_{l=1}^U A_l \cdot \prod_{l=1}^{NIL} A_l \cdot \prod_{l=1}^{NRS} A_l \quad (5-28)$$

For an outage of the scheduled unit or WTG i , the probability of loss of load is given by

$$LP_{i,t}^f = FP_t^f \cdot \prod_{l=1; l \neq i}^U A_l \cdot \prod_{l=1}^{NIL} A_l \cdot \prod_{l=1}^{NRS} A_l \cdot \prod_i (1 - A_i), \quad f \in \{1, 2\} \quad (5-29)$$

Equations (5-26) and (5-28) are used to compute the probability and its load curtailment on loss of load owing to forecast errors without unit outages. Equations (5-27) and (5-29) are used to compute the probability and its load curtailment due to forecast errors and unit i outage. The binary status on the loss of load (1 or 0) is determined through

$$\frac{LC_t^0}{TCR} \leq \theta_t^0 \leq 1 + \frac{LC_t^0}{TCR} \quad (5-30)$$

$$\frac{LC_{i,t}^f}{TCR} \leq \theta_{i,t}^f \leq 1 + \frac{LC_{i,t}^f}{TCR} \quad f \in \{1, 2\} \quad (5-31)$$

where

TCR summation of all available energy including wind energy and reserve procured [MW]

θ_t^0	binary status on the loss of load owing to large net forecast error without unit outage at hour t
$\theta_{i,t}^f$	binary status on the loss of load with unit i outage at hour t .

The general EENS (MWh) term that incorporates the net forecast errors at time t is formulated as

$$EENS_t = \theta_t^0 \cdot LC_t^0 \cdot LP_t^0 + \sum_{f=1}^2 \sum_{com} EENS_{com,t}^f \quad (5-32)$$

$$EENS_{com,t}^f = \theta_{com,t}^f \cdot LC_{com,t}^f \cdot LP_{com,t}^f \quad (5-33)$$

where

com a set of units' combination outages $com = \{C_s, C_{IL}, C_O\}$. Subset $C_s = \{i, (i, j), (i, j, k), \dots\}$ is the outage combination for committed generation units; subset $C_{IL} = \{0, i, (i, j), \dots\}$ is a set of combinations when ILs failed to operate; and subset $C_O = \{0, i, (i, j), \dots\}$ is a set of combinations when rapid-start units failed during start up at hour t .

The expected energy not served is the summation of EENS from all various service providers. However, when load and wind forecast errors are considered, the combination of equation (5-32) and the EENS summation gives

$$EENS_t = \theta_t^0 \cdot LC_t^0 \cdot LP_t^0 + \sum_{f=1}^2 \left(EENS_t^{s(f)} + EENS_t^{IL(f)} + EENS_t^{O(f)} \right) \quad (5-34)$$

and

$$EENS_t^{s(f)} = \sum_{i=1}^U EENS_{i,t}^f + \sum_{i=1}^U \sum_{j>i}^U EENS_{i,j,t}^f + \sum_{i=1}^U \sum_{j>i}^U \sum_{k>j}^U EENS_{i,j,k,t}^f \quad (5-35)$$

$$EENS_t^{IL(f)} = \sum_{k=1}^{NIL} \sum_{i=1}^U EENS_{k,i,t}^f + \sum_{k=1}^{NIL} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^f + \sum_{j=1}^{NIL} \sum_{k>j}^{NIL} \sum_{i=1}^U EENS_{j,k,i,t}^f \quad (5-36)$$

$$\begin{aligned} EENS_t^{O(f)} = & \sum_{k=1}^{NRS} \sum_{i=1}^U EENS_{k,i,t}^f + \sum_{k=1}^{NRS} \sum_{i=1}^U \sum_{j>i}^U EENS_{k,i,j,t}^f + \sum_{k=1}^{NRS} \sum_{i=1}^U \sum_{h=1}^{NIL} EENS_{k,i,h,t}^f \\ & + \sum_{j=1}^{NRS} \sum_{k>j}^{NRS} \sum_{i=1}^U EENS_{j,k,i,t}^f \end{aligned} \quad (5-37)$$

The superscript f in equations (5-34) to (5-37) indicates that EENS is to be computed according to the probability depicted in Table 5-4. The computation of these EENS terms with or without rapid-start units is the same as that discussed in Chapter 4.

The steps to compute the EENS with forecast error components are shown in Fig. 5-7.

5.3.4 Objective Function

The wind turbine generators generate electric power to meet the system demand and their total energy is incorporated into the system constraint,

$$\sum_{i=1}^U P_{i,t} \cdot u_{i,t} + P_{Total,t}^W = Load_t \quad t = \{1 \dots T\} \quad (5-38)$$

The modelling of the objective function, is exactly the same as those that have been derived in the previous chapters of this thesis. The EENS of the objective function is replaced by the EENS derived in this chapter and the constraint to balance the supply and demand is replaced by equation (5-38). The rest of the terms in the objective function remain the same since wind turbine generators are non-dispatchable.

Figure 5-7 A flow chart to illustrate the computation of EENS with forecast error components at hour t .

5.3.5 Simulation Results and Discussion

In this sub-section, the results on how the forecast errors will affect the electric power system cost and reliability are first presented. This is followed by simulation results and a comparison among systems with mix generation. The studies are conducted either on the 26-thermal unit system or the same 26-thermal unit system with 6 hydro units and 3 ILs. The energy/reserve offer prices for the OCGTs are identical to those of the demand units scheduled for energy and SR/NR. A wind farm of 100 WTGs, unless otherwise stated, is incorporated in the study. The data of these WTGs is shown in Table A-8 and the wind speed data obtained from [181] has been modified and represented in Table A-9. Unless otherwise stated, the studies are simulated with an average of 4.8% wind energy penetration over the 24-hour study period. Each WTG is assumed to receive the same magnitude of wind speed in the study. The parameter α on load forecast error is set to 10%. VOLL is set to 4 \$/kWh. The allocation of NR and IL reserve is restricted to not more than 50% of OR.

A. *Standard Deviation Behaviour of Forecast Errors*

The studies which examine the relation between the total installed capacity of WTGs (P^{WI}) and the standard deviation of the wind power forecast error ($\sigma_{w,t}$), and the relation between the standard deviation of the total forecast error ($\sigma_{total,t}$), wind power generation and load forecast error are performed in this sub-section. Based on (5-21) and earlier discussions, when the wind speed is low, a small quantity of wind energy is generated. The total installed capacity of WTGs tends to dominate the standard deviation value. This is verified in Fig. 5-8. The standard deviation of the wind power forecast error at low wind power is nearly identical to the product term of the total installed capacity of WTGs in (5-21), i.e. $0.04 \cdot P^{WI}$. When the wind speed increases, this increases the wind power generation. The standard deviation of the wind power forecast

error increases too and gradually deviates from the product term of the total installed capacity of WTGs.

Figure 5-8 A plot on the standard deviation of the wind power forecast error against wind power generation and total installed WTG capacity.

Fig. 5-9 shows that at low wind power caused by low wind speeds and/or small number of WTGs, the standard deviation of the total forecast error is dominated by the load forecast error. The standard deviation of the total forecast error in (5-22) is small at low system demand and it increases with the system demand. With the increase in wind power and system demand, the increase in the standard deviation of the total forecast error becomes smaller as can be seen from the gap between two successive curves towards the right-hand side of the plot. The increase in wind power causes the wind forecast error to become a dominant factor in (5-22), particularly at low demand load as reflected by the gradual increase in the standard deviation of the total forecast error. At high demand load, the standard deviation of the total forecast error is unaffected by the increase in wind power.

Figure 5-9 A plot on the standard deviation of the total forecast error against wind power generation.

B. Forecast Error Studies on Cost Incurred and Reserve Procured

This simulation is performed on the 26-thermal unit system. The standard deviation of the load forecast error is formulated as in equation (5-20), and α is varied from 2.5% to 20% as depicted in Fig. 5-10. This simulation is designed to study how the forecast error will affect the cost and reserve quantities when forecast error is incorporated in EENS.

With the increase in load forecast errors, more reserve is needed in order to satisfy the system constraint. Hence, this results in additional units to be started up and incurs additional start up cost and fuel cost to satisfy the EENS criterion. This cost increase is depicted in Fig. 5-11. For a small increase in load forecast errors, the system reliability at optimal cost improves with more reserve procured. However, a further increase in load forecast errors results in a deterioration in system reliability. The optimal total cost tends to shift towards the right side of the plot in Fig. 5-11, even though additional reserve has been procured as shown in Fig. 5-12. The reserve procured is the total amount computed over the 24-hour study period.

Figure 5-10 Plot of system demand and demand forecast error with varying α

Figure 5-11 Plot of total cost versus unreliability level at $VOLL = 4$ \$/kWh with varying α

Figure 5-12 Plot of 24-hour period reserve procured versus unreliability level at VOLL = 4 \$/kWh with varying α

C. Availability of WTG modelling Study

Unlike conventional thermal units, WTGs are much smaller in capacity but large in number. They are connected to substations via points of common coupling. Outages of WTGs can be modelled in two ways: individual turbines with availability states (WTG Method I) and single unit representing all the wind turbines in a wind farm (WTG Method II) [182].

The probability of failure for any WTG is considered to be exponentially distributed as a function of mean time to failure as shown below,

$$p_{WTG}(t) = 1 - e^{\frac{-t}{MTTF}} \quad (5-39)$$

This probability is similar to the failure rate of a conventional thermal unit with a lead time, τ . For WTG Method II, this equation is computed only once representing all the WTGs in the wind farms. For WTG Method I, when all WTGs in the wind farm are

identical in MW production and parameters, the failure of one WTG is independent of the rest of WTGs. The failure probability of x units out of the total number of WTGs (NWG) is given by a binomial distribution,

$$P(x) = \frac{NWG!}{(NWG - x)!x!} \cdot p_{WTG}^x \cdot (1 - p_{WTG})^{NWG-x} \quad (5-40)$$

The number of possible combinations of WTG outages (CFnos) is

$$CFnos = \frac{NWG!}{(NWG - x)!x!} \quad (5-41)$$

Equations (5-40) and (5-41) can be integrated into the computation algorithm to reduce the computation burden during the iterative process when the number of WTGs is large. Figs. 5-13 and 5-14 depict the total costs and total reserve procured over the study horizon for three systems: a base case of 26-thermal unit system considering the demand forecast error, and systems based on WTG Method I and II.

Fig. 5-13 shows that both WTG methods yield a reduction in the total cost as compared to that of the base case. As the outage of WTGs should be independent of each other, WTG Method II is not a representative of actual WTG operation. Excessive reserve will be procured for this method and may lead to a conclusion that a higher reserve is needed for system with wind energy penetration. Hence, WTG Method II is not able to provide an accurate representation of the real power system.

Figure 5-13 Total cost versus unreliability level at VOLL = 4 \$/kWh on WTG availability study

Figure 5-14 Total reserve procured over the 24-hour period versus unreliability level at VOLL = 4 \$/kWh on WTG availability study

For WTG Method I, the WTGs are modelled as each independent unit. A single WTG outage has minuscule effect on the system as its production is relatively small compared to the total system production. The probability of failure for each WTG causes a relative

small reduction towards the system reliability. This method provides a more realistic simulation on the stochastic nature of WTG outages. Hence, this work has adopted WTG Method I as the basis for WTG modelling.

D. Wind Energy Studies with Varying Demands

The benefit of integrating wind power into the conventional electric power system can be quantified by varying system demands and wind speeds over a specific range. The EENS assessment criterion is set to 0.35 MWh. The scaling wind speed is represented by $WSx\#$ (where WS – Wind Speed; x – multiply; and $\#$ - a scaling factor). Fig. 5-15(a) shows that the required system reserve increases as wind energy penetration decreases, or as load demand increases from 500 to 2000 MW at any wind energy penetration level. Between 2000 and 2600 MW, the required reserve does not show a significant increase when load increases beyond 2600 MW. The required reserve may even decrease and level off for any wind energy penetration other than $WSx2.0$. Beyond 2600 MW, the additional committed units such as units 21 to 23 are restricted to ramping constraints of 98.5 MWh, and could not reach the maximum capacity of 197 MW. Therefore, other units have to ramp up their MW outputs to meet the system demand requirement. This results in a smaller number of units available for reserve allocation, since they have reached their maximum unit capacity. With high penetration of wind energy, the net thermal MW generation decreases, and fewer conventional thermal units are committed. Energy and reserve are scheduled and allocated to less expensive units.

Fig. 5-15(b) is another illustration of Fig. 5-15(a) and reiterates that the required reserve increases as wind energy penetration decrease from $WSx2.0$ (high wind – high wind energy penetration) to $WSx1.0$ (low wind – low wind energy penetration) at any constant load level between 1500 and 2000 MW. In other words, the reserve procured at high wind energy penetration is smaller than that at low wind energy penetration. This contradicts the general belief that reserve increases as wind energy penetration increases.

Figure 5-15 Plots of reserve procured at VOLL = 4 \$/kWh for systems with wind speed and system demand variations

E. System Reliability Studies of Wind Energy

The system reliability study for the system with 100 WTGs is accomplished by a gradual increase in wind speed over the demand period. This study also includes an increase in the WTG number in steps of 100 (up to 400) to simulate significant wind energy penetration.

The increase in the number of WTGs is represented as WTGx# (where WTG – Wind Turbine Generator; x – multiply; and # - a scaling factor) in Fig. 5-16. It can be seen that with the wind energy integrated into the conventional thermal unit system, the total cost reduces in proportion to the increase of wind energy penetration. There is a slight reliability improvement at low wind energy penetration of WTGx100 when wind speed increases, as delineated by a dashed-line arrow. This slight reliability improvement is due to the large number of WTGs with availability of 1920 hours which is higher than the availability of most online conventional thermal units. However, the effect of energy fluctuation at high wind energy penetration predominates over the effect of WTG availability owing to the uncertainty of wind flows and also to the reduction in the number of conventional thermal units operate online. The former can be mitigated by the increment of reserve procured but at a higher total system cost which is not optimal. The system reliability at optimal cost and at high wind energy penetration (beyond WTGx200) deteriorates, as illustrated by a solid-line arrow shown in a downward direction.

The deviation of operation status among four systems: WSx1.4, WSx1.5, WSx1.6 and WTGx200 at their optimal cost at various hours are tabulated in Table 5-5. For WSx1.5, a higher number of conventional thermal units is scheduled for operation throughout the 24-hour studies period compared to that of the other systems. Consider Unit 12 with MTTF of 1960 hours. With the increase of its operation hours, the system reliability improves. For WSx1.4, although the operation hour for Unit 23 is two hours longer than

Unit 23 in WSx1.5 and the rest of the systems under comparison, its reliability at optimal cost is poorer compared to that of WSx1.5. This is because the MTTF of Unit 23 is only 950 hours. For those systems with a higher wind energy penetration than WSx1.5, the increase in wind energy penetration reduces the power generation from conventional thermal units and causes these units to stay offline. This reduces the system reliability at optimal cost which is illustrated in Fig. 5-16.

In general, integration of WTGs into the conventional thermal unit system has reduced the overall cost.

Figure 5-16 Plot of total cost versus unreliability level at VOLL = 4 \$/kWh for systems with variation in wind speed and wind energy penetration

F. System Configuration Studies with Renewable Energy Penetration

In this section, a comparison study on the reliability level at optimal cost and costs incur on reserve procurement, energy and EENS for the two types of renewable energy is presented.

Fig. 5-17 shows a plot between total cost and unreliability level. The four systems studied are: system with only thermal units, system with thermal and WTGs, system with thermal and hydro units, and system with both WTGs and Hydro units. From the figure, systems with renewable energy incorporation result in a lower total system procurement cost. Comparing the system with WTGs and system with hydro, the latter has a lower total cost due to the low EENS cost incurred. This is because WTGs do not contribute to reserve and the system reserve procured is much lower than the system with hydro units as depicted in Table 5-6. While for system incorporated with both types of renewable energy, it has the lowest total cost amount the system studied in this section.

Table 5-5(a) Unit operation status that deviates among the four systems at their optimal cost

Unit	System	Period																							
	Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
3	WSx1.5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1
	WTGx200	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1
4	WSx1.5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1
	WTGx200	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1
10	WSx1.5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WTGx200	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	WSx1.5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WTGx200	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	WSx1.5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	1	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WTGx200	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0

Table 5-5(b) Unit operation status that deviates among the four systems at their optimal cost

Unit	System	Period																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
13	WSx1.5	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WTGx200	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
14	WSx1.5	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.4	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	WSx1.6	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
	WTGx200	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
23	WSx1.5	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
	WSx1.4	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
	WSx1.6	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0
	WTGx200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 5-17 Total cost versus unreliability level at VOLL = 4 \$/kWh for different renewable energy resource combinations

Table 5-6 A table on system reserve procured and various costs incurred for systems incorporated with renewable energy resources

System Combination	Unreliability Level at Optimal Total Cost	Total Reserve Procured (MW)	Total Reserve Cost (\$)	Total Energy Cost (\$)	Total EENS Cost (\$)	Total Cost (\$)
Only Thermal Units	0.50	5054	8,564	733,932	47,861	781,793
Thermal-WTGs	0.49	4983	8,365	680,651	46,872	727,523
Thermal-Hydro	0.07	8908	15,625	677,520	6,594	684,114
Thermal-WTGs & Hydro	0.15	7996	13,928	619,360	14,218	633,578

G. System Configuration Studies with Wind Energy Penetration

Different system mix of ILs, OCGTs and hydro units is modelled. The purpose of this simulation is to study the effect of different system mix with/without wind energy penetration on reliability and total cost. The combinations of services providers without

WTGs are labelled as (C# where # is the case study number), and those with WTGs are labelled as (C*#). The thermal units are labelled as THs. OCGTs and hydro units are modelled such that they can offer NR in the electricity market. A mean hourly wind energy penetration of 4.8% over the demand levels of the study horizon is modelled.

There is a degradation in system reliability at their optimal cost in most combinations as shown in Figs. 5-18 and 5-19.

These optimal costs are indicated with a circle in the plots. The amount of cost reduction for the incorporation of WTG is the cost difference between C1 and C*9 at the same reliability level of Fig. 5-18, where C1 is the base case system, and C*9 is the thermal units system with WTGs. An average of at least 8.65% cost reduction can be achieved for each reliability level.

Fig. 5-20 shows the cost breakdowns at the optimal total cost for each mix combination. It manifests that the integration of WTGs generally will result in a higher EENS cost in all cases except for C*6. Its counterpart C6 incurred higher EENS cost because unit 22 has been committed during peak hours. This unit is having a capacity of 197 MW with a poor MTTF of 950 hours. The same unit has not been scheduled to commit for C*6 with WTG integration. Although the same unit has also been committed in C7 and C8, the EENS value is able to reduce significantly because of the high reserve quantity procured at optimal cost. The total reserve procured for the 24-hour study period for cases C6, C7 and C8 are 8244 MW, 9391 MW and 9661 MW respectively. A higher EENS cost is incurred in all other cases because WTGs are highly dependent on uncertain wind speeds, thus negating the effects of unit reliability with high MTTF values.

Figure 5-18 Total cost versus unreliability level at VOLL = 4 \$/kWh for different resource combinations with WTGs

Figure 5-19 Total cost versus unreliability level at VOLL = 4 \$/kWh for different resource combinations without WTG

A percentile plot of reserve allocation at optimal cost among different mix combinations is shown in Fig. 5-21. With the increase in the number of reserve providers which offer a competitive reserve price, the share of reserve which is allocated to conventional thermal units traditionally has been reallocated to other sources. This is particularly true when the system is integrated with WTGs since it allows more energy providers to offer reserve in stead of energy as the energy need has been reduced by the penetration of wind energy.

Figure 5-20 Bar-chart showing optimal total costs for different system configurations

Figure 5-21 Reserve allocation in percentile at optimal total costs from different reserve providers

On the basis of these findings and the earlier results presented in this chapter, it can be deduced that WTG integration generally will degrade the system reliability. Nonetheless, a proper unit mix in the system may improve the reliability.

5.4 Study on Large Conventional System with Wind Energy Distribution Generation (WTG DG)

In this section, three studies are performed. They are (1) a comparison study between 26 and 104 conventional thermal units systems; (2) a comparison study between systems

with different WTG DG size; and (3) the effect of the operating reliability of large conventional units on system reliability and cost, with WTG penetration. For the 104-thermal unit system, it is a system with four times the 26-thermal unit system and loads.

5.4.1 104 Conventional Thermal Unit System

With the increase in the number of conventional thermal units scheduled to be connected online, the system reliability improves tremendously as shown in Fig. 5-22. This improvement is due to the availability of reserve from the 104-thermal unit system and more units available for reserve contribution, as compared to the 26-thermal unit system.

Figure 5-22 Total cost verse unreliability level at VOLL = 4 \$/kWh for 26 and 104-thermal unit systems

5.4.2 System with Different Wind Energy Distributed Generation Studies

A comparison study among systems with different size of wind energy penetration is performed. From Table 5-7, the system become more unreliable with low wind energy penetration, but the reliability improves with more wind energy penetration in a larger conventional thermal unit system. This contradicts that of the 26-thermal unit system

with WTG. For the 26-thermal unit system, due to its small number of large conventional units that can be scheduled online, its system reliability deteriorates with the increase of WTG penetration. For a large conventional thermal unit system, the increase in WTG penetration results in a reduction in the number of online expensive conventional thermal units of low operating reliability. Most online units have a higher operating reliability and a lower operating cost. Thus, more spinning reserve is procured from these units with high operating reliability. This results in a better system reliability and a lower total cost.

Table 5-7 A table on system unreliability level, reserve procured and total system costs incurred for systems with different WTG distribution generation

Combination	Unreliability		EENS (kWh)	Total Cost (\$)
	Level	Reserve (MW)		
104 Thermal Units System	0.07	9612	1623	2,839,557
104 THs with 100 WTG System	0.11	14314	2604	2,824,318
104 THs with 200 WTG System	0.1	14412	2361	2,769,812
104 THs with 300 WTG System	0.03	15085	687	2,717,567

5.4.3 Effect of Operating Reliability of Large Thermal Units on System with WTG Penetration

A study on how the operating reliability of large conventional thermal units affects the overall system reliability and cost is performed. The largest MW capacity units in the system have their MTTF reduced below 1000 hours. Fig. 5-23 and Table 5-8 are the results obtained from the simulations. When large thermal units have poor operating reliability, the overall system reliability deteriorates, even though more reserve is procured. In addition, the total system cost increases.

Figure 5-23 Total cost versus unreliability level at VOLL = 4 \$/kWh for 104 thermal units systems with WTG and largest MW thermal units have lower MTTF.

Table 5-8 System unreliability level, reserve procured and total system costs incurred for systems with WTG and largest thermal units have lower MTTF

Combination	Unreliability Level	Reserve (MW)	EENS (kWh)	Total Cost (\$)
104 TH with 300 WTG System	0.03	15085	687	2,717,567
104 TH with Low MTTF for Large Units & 300 WTG System	0.08	15111	1855	2,722,438

The results in this section show that large conventional thermal unit systems have a better system reliability as compared to that of small systems when distributed generation such as WTGs are part of this conventional system. However, the improvement in system reliability still relies on the operating reliability of those large capacity conventional thermal units.

5.5 Discussion on Applications on Proposed Works

This research work enables policy makers, ISOs and GENCOs to use the proposed scheme for current and future generation expansion to obtain optimal system operation costs. The studies can be used to decide the types of energy sources to implement for power generation, and to attract investors to plant suitable energy sources for participation in the electricity market.

With progressive development of small scale localised electricity generation planting worldwide, the modelling of a power system is becoming more challenging. This small scale power system is able to make a region self-sufficient in electricity supply via micro-grid management system operation and control. It makes use of the existing grid to transmit its supply from the sources to the end-users. When operating in ‘Grid-Connect’ mode, the micro-grid supplies the surplus energy generated by selling back to the main grid.

The objective of energy management of a micro-grid is to optimise its operation costs such as fuel cost, maintenance costs and purchase cost of electricity from the main grid. It is the responsibility of micro-grid owners to ensure a reliable electricity supply. These owners are responsible for the service interruption of customers caused by the micro-grid. The sources of energy may vary from diesel generators, run-of-river hydro generators, wind turbines, photovoltaic and energy storage systems. They may not be necessary from a single provider. A bigger investor may have combined-cycle power generation or combined-heat-and-power (CHP) operation. The customers of the micro-grid can also prioritise their loads and participate in DSM within the micro-grid.

Based on the above description on the operation and control of a micro-grid and its objective, the proposed scheme is also suitable for the owner to plan for the types of

energy sources to be introduced in the network to achieve its objective. However, additional energy sources such as photovoltaic and energy storage need to be modelled.

The proposed scheme can also be used in a centralised dispatch management to study the impact when the micro-grid operates in ‘Grid-Connect’ mode. A micro-grid can be modelled as a ‘Load’, but it will not only consume energy but also generate and sell energy back to the main network. In this case, the objective function, such as (3-23) etc, needs to be modified as follows:

$$\begin{aligned} \text{Min} \left\{ \sum_{t=1}^T \sum_{i=1}^U \left[C_i^E (P_{i,t}, MC_{i,s}, u_{i,t}) + cr_i^{SU} \cdot u_{i,t} (1 - u_{i,t-1}) + C_i^{SR} (cr_i^{SR} \cdot R_{i,t} \cdot u_{i,t}) \right] \right. \\ \left. + \sum_{i=1}^{NMG} C_i^{MG} \cdot u_{i,t}^{MG} + \sum_{t=1}^T EENS_t \cdot VOLL \right\} \end{aligned} \quad (5-42)$$

subjected to

$$\sum_{i=1}^U P_{i,t} \cdot u_{i,t} + \sum_{i=1}^{NMG} P_{i,t}^{MG} \cdot u_{i,t}^{MG} \cdot u_{i,t}^{MG-C} = Load_t + \sum_{i=1}^{NMG} P_{i,t}^{MG} \cdot (1 - u_{i,t}^{MG}) \cdot u_{i,t}^{MG-C},$$

$$t = \{1 \dots T\} \quad (5-43)$$

where

C_i^{MG}	Cost of selling power from micro-grid i to the main grid [\$/h]
$u_{i,t}^{MG}$	Operation status of micro-grid i at hour t (1 indicates selling power, and 0 means operate as a load)
$u_{i,t}^{MG-C}$	Connection status of micro-grid i at hour t (1 indicates grid connected, and 0 means stand-alone)
NMG	Number of micro-grids allowed to be connected to the main grid.

The EENS contributed by the micro-grid also needs to be modelled. In addition, other new metrics are needed to determine the micro-grid operation status $u_{i,t}^{MG}$ and connection status $u_{i,t}^{MG-C}$, as well as its reliability, purchase/sale probability and islanded operation probability as presented in [183].

The proposed scheme can therefore be used either in standalone micro-grid management or central dispatch with micro-grid control. However, with this increase in complexity and different operating characteristic of additional energy sources, a more powerful computer system with a bigger SRAM size is needed.

5.6 Summary

In this chapter, the simulation results show that the incorporation of hydro electric power plant not only reduces the total cost for energy scheduling and reserve allocation but also improves the system reliability. With the consideration of forecast errors in the modelling process, the total cost and reserve amount procured increase. When wind energy is incorporated in the conventional thermal units system, the system reliability improves slightly at low wind energy penetration but deteriorates at high wind energy penetration. These phenomena were observed for most of the resource mix systems. Nonetheless, the generation of wind energy shows cost reduction.

These studies show that unique characteristics of energy and reserve providers from different sources have a direct effect on the performance of the electric power system. The results and observations can serve as a useful guide to assist ISOs in deploying energy/reserve providers in an electric power system with wind energy.

Chapter 6

Conclusions and Recommendations

6.1 Conclusions

Introduction of competition into the traditional electric power industry allows different types of energy and reserve providers to participate in the electricity market. The electricity market participants can be electricity consumers at the demand side, renewable energy providers or electricity suppliers that are small in generation capacity and able to start up rapidly but with lower starting reliability. The ISO, thus, faces challenging problems with these participants in securing sufficient reserve to sustain system reliability for power system operation.

In this thesis, a probabilistic approach with an initial deterministic reserve criterion is introduced for the ISO to procure a certain amount of generation capacity as 10-minute OR to ensure that the power system is able to withstand unforeseen outages of generation units or sudden load increase without having to resort to load shedding. Instead of using a risk index, a criterion in MWh is used to terminate the reserve procurement iterative process and the “MWh” indicates clearly the expected amount of un-served energy allowed for each time interval. With this approach the reserve procured will not be too low when the demand is high and not too high when the demand is low.

The integration of starting reliability into the operating reliability for rapid-start units using the joint probability distribution approach is proposed. The calculated joint probability is used to compute the EENS which then determines the necessary reserve

amount to be procured. EENS is computed considering the time the outage occurred to the time when rapid-start units are connected to the network for energy contribution, or up to their lead time. The EENS is calculated with these different timings and the EENS value will be more precise than that of the common method used.

A novel methodology in the formulation of EENS considering the forecast errors on load demand and wind generation through determination of probabilities using the normal distribution approach is proposed. The EENS is computed for unit outages with and without these forecast errors that cause the loss of load. The final EENS is then integrated into the objective function of the UC problem. This UC modelling process has thus not only considered the outage probability of each individual wind turbine but also took into account the uncertainties of environment factors in determining the energy, reserve and EENS costs.

The integration of ILs from demand side has shown that the system total cost can be reduced and a higher system reliability is obtained. A study on VOLL is performed and it can infer that the increase of VOLL generally causes the overall cost to increase. A penalty cost is proposed to impose on the ILs and grid service providers when the UFRs/CBs that are connected to the interruptible loads malfunction. This will improve the reliability of system operation and reduce the energy procurement cost.

The importance of modelling the rapid-start units with starting reliability is investigated and demonstrated by a number of case studies. This is especially done for systems with OCGTs. Energy and reserve price offers from OCGTs have to keep low to compete with other sources in the electricity market. The penalty imposed on OCGTs who failed to start up for NR contribution allows the providers to maintain these units at their most reliable state of operation.

There is no doubt that the penetration of wind energy causes a reduction in the system total cost. A significant number of conventional generation units has to be committed online particularly during time intervals with high system demand and low wind energy in order to provide the necessary amount of reserve to sustain system reliability.

The major contributions of this research work are as follow,

- ❖ The deterministic and probabilistic approach for the UC objective function is formulated to incorporate the energy/reserve providers by simultaneous scheduling of energy and reserve.
- ❖ A practical methodology to formulate the ILs reliability based on their types of power supply sources is proposed. This reliability is then integrated with the reliability of system and human behaviour to obtain the ILs reliability used for the EENS calculation.
- ❖ A technique to incorporate the starting probability and operating reliability of rapid-start units is presented. The results show that starting reliability has a great impact on the EENS cost.
- ❖ A technique to integrate load and wind power forecast errors and to represent them in terms of EENS is presented.
- ❖ An EENS plot that illustrates how EENS is contributed by different services providers is presented. This gives a better explanation and quantifies how each provider contributes to EENS.
- ❖ Finally, penalty cost functions are formulated to penalize the noncompliance services providers to improve the system reliability.

This work provides a useful overview of power system reliability and economics of conventional power systems with integration of different energy and reserve providers. The proposed technique could be used by Gencos to optimise their assets for resources

planning. It could also be used to assist the ISO in deploying energy/reserve providers more efficiently.

6.2 Recommendations for Future Research

The environmental and political factors have caused the tasks of managing the electric power system problems more uncertain and challenging for the engineers and researchers to tackle. This work has created a foundation platform that enables them to extend the studies in the following ways:

- ❖ The present work is modelled without transmission system representation in order to give a generic generation problem. Studies on systems with energy and reserve providers located at different nodes of a transmission system with the same providers but a different set of transmission networks can be implemented. The VOLL can be set to different nodal values in the studies. The results obtained will be useful for system planners to select suitable energy and reserve providers at different nodes to achieve better efficiency.
- ❖ The current work only considers a uniform wind speed for all WTGs in each time interval. Different wind speeds that could be implemented to simulate WTGs that are installed at different geographical altitudes and locations. Energy storage facilities could also be implemented to examine the reliability of the electric power system with energy storage.
- ❖ Other than penetration of wind energy, there has been an accelerated increase in the penetration of photovoltaic (PV) energy into the electric power system over the recent years. This work can further extend its reliability and economic studies on integration of photovoltaic renewable energy system. Methodologies and

techniques could be implemented for the PV integration considering irradiance forecast incorporating cloud flows/layers and temperature values as these factors will affect the performance of the PV system.

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Curriculum Vita

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Appendix

Table A-1 Operational parameters and offer prices of 6 thermal generators

Unit (i)	$P_i^{\min}$ (MW)	EL-1 (MW)	EL-2 (MW)	$P_i^{\max}$ (MW)	T_i^{on} (h)	T_i^{off} (h)	Initial Status (h)	MTTF	RUR_i (MW/h)	RDR_i (MW/h)
1	15.2	35.47	55.73	76	3	2	3	1960	38.5	80
2	25	50	75	100	4	2	-3	1200	51.0	74
3	54.25	87.83	121.42	155	6	3	5	960	77.5	77.5
4	140	210	280	350	8	5	10	1150	175.0	175
5	100	200	300	400	8	5	10	1100	200.0	200
6	100	200	300	400	10	5	10	1100	200.0	200

Table A-1 (cont) Operational parameters and offer prices of 6 thermal generators

Unit (i)	SC_i (\$)	No-load Cost (\$/MWh)	Segment 1 Cost (\$/MWh)	Segment 2 Cost (\$/MWh)	Segment 3 Cost (\$/MWh)
1	50	76	13.771	14.1261	14.4812
2	70	210	18.4673	18.7787	19.0903
3	150	121	11.3518	11.6628	11.9738
4	300	132	11.3971	11.6113	11.8255
5	500	271	8.0741	8.4621	8.8501
6	500	273	8.0881	8.4781	8.8681

Table A-2 Operational parameters and offer prices of 26 thermal generators

Unit (i)	$P_i^{\min}$ (MW)	EL-1 (MW)	EL-2 (MW)	$P_i^{\max}$ (MW)	T_i^{on} (h)	T_i^{off} (h)	Initial Status (h)	MTTF	RUR_i (MW/h)	RDR_i (MW/h)
1	2.4	5.6	8.8	12	1	0	-1	2940	48.0	60
2	2.4	5.6	8.8	12	1	0	-1	2940	48.0	60
3	2.4	5.6	8.8	12	1	0	-1	2940	48.0	60
4	2.4	5.6	8.8	12	1	0	-1	2940	48.0	60
5	2.4	5.6	8.8	12	1	0	-1	2940	48.0	60
6	4	9.33	14.67	20	2	0	-1	450	30.5	70
7	4	9.33	14.67	20	2	0	-1	450	30.5	70
8	4	9.33	14.67	20	2	0	-1	450	30.5	70
9	4	9.33	14.67	20	2	0	-1	450	30.5	70
10	15.2	35.47	55.73	76	3	2	3	1960	38.5	80
11	15.2	35.47	55.73	76	3	2	3	1960	38.5	80
12	15.2	35.47	55.73	76	3	2	3	1960	38.5	80
13	15.2	35.47	55.73	76	3	2	3	1960	38.5	80
14	25	50	75	100	4	2	-3	1200	51.0	74
15	25	50	75	100	4	2	-3	1200	51.0	74
16	25	50	75	100	4	2	-3	1200	51.0	74
17	54.25	87.83	121.42	155	6	3	5	960	77.5	77.5
18	54.25	87.83	121.42	155	6	3	5	960	77.5	77.5
19	54.25	87.83	121.42	155	6	3	5	960	77.5	77.5
20	54.25	87.83	121.42	155	6	3	5	960	77.5	77.5
21	68.95	111.63	154.32	197	8	4	-4	950	98.5	98.5
22	68.95	111.63	154.32	197	8	4	-4	950	98.5	98.5
23	68.95	111.63	154.32	197	8	4	-4	950	98.5	98.5
24	140	210	280	350	8	5	10	1150	175.0	175
25	100	200	300	400	8	5	10	1100	200.0	200
26	100	200	300	400	10	5	10	1100	200.0	200

Table A-2 (Cont) Operational parameters and offer prices of 26 thermal generators

Unit (i)	SC_i (\$)	No-load Cost (\$/MWh)	Segment 1 Cost (\$/MWh)	Segment 2 Cost (\$/MWh)	Segment 3 Cost (\$/MWh)
1	0.01	24	25.7498	25.9119	26.0741
2	0.01	24	25.8872	26.0568	26.2263
3	0.01	24	26.0268	26.206	26.3853
4	0.01	24	26.1592	26.3411	26.5229
5	0.01	25	25.2895	26.4722	26.6549
6	20	117	37.7109	37.8388	37.9667
7	20	118	37.8318	37.9663	38.1009
8	20	118	37.9582	38.1032	38.2481
9	20	118	38.0807	38.2335	38.3864
10	50	76	13.771	14.1261	14.4812
11	50	76	13.8073	14.17	14.5328
12	50	77	13.8416	14.2104	14.5793
13	50	77	13.8795	14.2573	14.6351
14	70	210	18.4673	18.7787	19.0903
15	70	211	18.559	18.865	19.171
16	70	211	18.6485	18.8475	19.2465
17	150	121	11.3518	11.6628	11.9738
18	150	120	11.3875	11.7052	12.0229
19	150	120	11.4201	11.7432	12.0663
20	150	120	11.4502	11.7773	12.1045
21	200	239	23.4677	23.6888	23.9099
22	200	240	23.5695	23.7915	24.0134
23	200	240	23.6749	23.8994	24.124
24	300	132	11.3971	11.6113	11.8255
25	500	271	8.0741	8.4621	8.8501
26	500	273	8.0881	8.4781	8.8681

Table A-3 Bidding data of interruptible load in reserve market

Interruptible Load Agent	Bidding Price (\$/MWh)	Bidding Quantity (MW)	Reliability Factor, π
1	1	20	9970
2	2	20	9970
3	3	15	9970

Table A-4 Operation parameters of hydro generators

Unit (i)	$P_i^{h,min}$ (MW)	$P_i^{h,max}$ (MW)	RR_i^h (MW/h)	Initial Status	T_i^{on} (h)	T_i^{off} (h)	MTTF	HSC_i (\$)
1	9	70	2100	-1	1	1	1980	300
2	4	70	2100	-1	1	1	1990	450
3	17	115	3450	-1	1	1	1990	540
4	9	80	2400	-1	1	1	1980	250
5	2	60	1800	-1	1	1	1970	400
6	19	120	3600	-1	1	1	1970	700

Table A-5 Reservoir parameters of hydro plants

Unit (i)	W_i^{min} (Hm ³)	W_i^{max} (Hm ³)	W_i^0 (Hm ³)	W_i^T (Hm ³)	$J_{i,t}$ (Hm ³ /h)	Q_i^{min} (Hm ³ /h)	Q_i^{max} (Hm ³ /h)
1	70	150	100	100	4	1	10
2	40	130	80	80	3	1	10
3	100	240	170	170	2	1.3	20
4	60	160	100	100	3	1	10
5	50	140	90	90	2	1	10
6	120	300	180	180	1.22	1.5	20

Table A-6 System demand for 24-hour period

Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)
1	1700	7	2000	13	2590	19	2500
2	1730	8	2430	14	2550	20	2550
3	1690	9	2540	15	2620	21	2600
4	1700	10	2790	16	2650	22	2480
5	1740	11	2800	17	2550	23	2200
6	1900	12	2590	18	2530	24	1840

Table A-7 Properties of open cycle gas turbines

Units	Reliability Code	Starting Up Probability	MTTF	Spinning Reserve Offering Prices (\$/MWh)	Non-Spinning Reserve Offering Prices (\$/MWh)	
					Case 1	Case 2
6	LA	0.990	450	3.79667	7.55500	3.77750
7				3.81009	7.59342	3.79671
8				3.82481	7.60814	3.80407
9				3.83864	7.62197	3.81099
27	HA	0.998	620	3.79667	7.55500	7.55500
28				3.81009	7.59342	7.59342
29				3.82481	7.60814	7.60814
30				3.83864	7.62197	7.62197

Table A-8 Generation data of wind turbine

Number of WTG	100
WTG capacity (MW)	2.5
MTTF (h)	1920
Cut-in wind speed (m/s)	6.2
Cut-out wind speed (m/s)	21
Rated wind speed (m/s)	12

Table A-9 Wind speed data for 24-hour period

Hour	Wind Speed (m/s)	Hour	Wind Speed (m/s)
1	6.72	13	7.03
2	6.69	14	7.06
3	6.69	15	6.89
4	6.58	16	6.67
5	6.64	17	6.67
6	6.64	18	6.58
7	6.64	19	6.67
8	6.64	20	6.75
9	6.64	21	6.81
10	6.72	22	6.83
11	6.83	23	6.89
12	7.00	24	6.47